PART 70 SIGNIFICANT SOURCE MODIFICATION AND MAJOR MODIFICATION UNDER PREVENTION OF SIGNIFICANT DETERIORATION

OFFICE OF AIR QUALITY

Southern Indiana Gas and Electric Company (SIGECO)
A. B. Brown Generating Station
W. Franklin Road and Welborn Road
West Franklin, Indiana 47620

(herein known as the Permittee) is hereby authorized to construct and operate subject to the conditions contained herein, the emission units described in Section A (Source Summary) of this approval.

This approval is issued in accordance with 326 IAC 2 and IC 13-15 and IC 13-17.

This approval is also issued under the provisions of 326 IAC 2-2, 40 CFR 52.21, and 40 CFR 52.124 (Prevention of Significant Deterioration), with conditions listed on the attached pages.

Source Modification No.: PSD 129-12029-00010	
Issued by: Original Signed by Paul Dubenetzky Paul Dubenetzky, Branch Chief Office of Air Quality	Issuance Date: November 29, 2001

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SECTION A SOURCE SUMMARY

This approval is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the emission units contained in conditions A.1 and A.2 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional approvals or seek modification of this approval pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)]

The Permittee owns and operates a stationary electricity generating station.

Responsible Official:	Ron Jochum
Source Address:	W. Franklin Road & Welborn Road, West Franklin, Indiana 47620
Mailing Address:	20 N.W. Fourth Street; P.O. Box 3606, Evansville, IN 47735-3606
Telephone Number:	812-465-4114; Allen K. Rose, Environmental Specialist, onsite contact
SIC Code:	4911
County Location:	Posey
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Major Source, Part 70 Permit Program Major Source, under PSD Rules 1 of 28 Source Categories Major Source, Section 112 of the Clean Air Act

A.2 Emissions Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(15)]

This stationary source is approved to modify and operate one (1) existing simple-cycle, natural gas-fired combustion turbine, designated as unit ABB CT No. 3, with a maximum heat input capacity of 1110.9 MMBtu/hr (higher heating value (HHV) with natural gas fuel condition), a maximum output of 109 MW, and a nominal output of 80 MW, utilizing No. 2 distillate oil as a back-up fuel source (maximum heat input capacity of 1195.2 MMBtu/hr at HHV condition). NOx emissions are controlled by dual fuel dry low-NOx (DLN) combustors, with steam injection for additional NOx reduction when firing distillate oil. Inlet fogging and steam augmentation may be used to enhance power production.

A.3 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability);

(c) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3).

A.4 Acid Rain Permit Applicability [40 CFR Part 72.30]

This stationary source is required to have a Phase II, Acid Rain permit by 40 CFR Part 72.30 (Applicability) because A.B. Brown Units 1, 2, and 3 are affected units as defined in 40 CFR 73, Subpart B, Section 73.10, Table 2 (Phase II Allowance Allocations). (Note: The ABB No. 3 CT was originally identified as a planned Boiler No. 4. This identification was clarified and corrected to a turbine identified as Unit No. 3 in a pending revision to the Acid Rain permit for the source.)

An Acid Rain permit for Units 1, 2, and 3 at the source, AR 129-5153-00010, was issued on December 31, 1997. AR 129-5153-00010 provides Phase II allowance allocations 640 tons per year for the period of 2000 to 2009 and 639 tons per year for the period of 2010 and beyond for ABB No. 3 CT.

SECTION B GENERAL CONSTRUCTION CONDITIONS

B.1 Definitions [326 IAC 2-7-1]

Terms in this approval shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2 and 326 IAC 2-7) shall prevail.

B.2 Effective Date of the Permit [IC13-15-5-3] [40 CFR 124]

Pursuant to 40 CFR Parts 124.15, 124.19, and 124.20, if public comments are received on the draft permit during the public comment period, the effective date of this permit will be thirty-three (33) days from its issuance. If no public comments are received, the effective date of this permit will be the date of issuance of the permit.

B.3 Permit Expiration Date [326 IAC 2-2-8(a)(1)] [40 CFR 52.21(r)(2)]

Pursuant to 40 CFR 52.21(r)(2) and 326 IAC 2-2-8(a)(1) (PSD Requirements: Source Obligation), this permit to construct shall expire if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is discontinued for a continuous period of eighteen (18) months or more. The commissioner may extend the eighteen (18) month period upon a satisfactory showing that an extension is justified.

B.4 Significant Source Modification [326 IAC 2-7-10.5(h)]

This document shall also become the approval to operate pursuant to 326 IAC 2-7-10.5(h) when, prior to start of operation, the following requirements are met:

(a) The attached affidavit of construction shall be submitted to the Office of Air Quality (OAQ), Permit Administration & Development Section, verifying that the emission unit was modified as proposed in the application. The emissions unit covered in the Significant Source Modification approval may begin operating on the date the affidavit of construction is postmarked or hand delivered to IDEM if constructed as proposed.

(b) If actual construction of the emissions unit differs from the construction proposed in the application, the source may not begin operation until the source modification has been revised pursuant to 326 IAC 2-7-11 or 326 IAC 2-7-12 and an Operation Permit Validation Letter is issued.

(c) The Permittee shall receive an Operation Permit Validation Letter from the Chief of the Permit Administration & Development Section and attach it to this document.

(d) The changes covered by the Significant Source Modification will be included in the Title V draft.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

C.1 Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]

(a) Where specifically designated by this approval or required by an applicable requirement, any application form, report, or compliance certification submitted under this approval shall contain certification by a responsible official of truth, accuracy, and completeness. This certification, shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) One (1) certification shall be included, using the attached Certification Form, with each submittal requiring certification.

(c) A responsible official is defined at 326 IAC 2-7-1(34).

C.2 Multiple Exceedances [326 IAC 2-7-5(1)(E)]

Any exceedance of a permit limitation or condition contained in this permit, which occurs contemporaneously with an exceedance of an associated surrogate or operating parameter established to detect or assure compliance with that limit or condition, both arising out of the same act or occurrence, shall constitute a single potential violation of this permit.

C.3 Preventive Maintenance Plan [326 IAC 2-7-5(1),(3) and (13)] [326 IAC 2-7-6(1) and (6)] [326 IAC 1-6-3]

(a) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) when operation begins, including the following information on each facility:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Permittee’s control, the PMPs cannot be prepared and maintained within the above time frame, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

The PMP and the PMP extension notification do not require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(b) The Permittee shall implement the PMPs as necessary to ensure that failure to implement a PMP does not cause or contribute to a violation of any limitation on emissions or potential to emit.

(c) A copy of the PMPs shall be submitted to IDEM, OAQ, upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ, may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or contributes to any violation. The PMP does not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(d) Records of preventive maintenance shall be retained for a period of at least five (5) years. These records shall be kept at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

C.4 Source Modification and Permit Amendment or Modification [326 IAC 2] [326 IAC 2-7-10.5] [326 IAC 2-7-11] [326 IAC 2-7-12] [40 CFR 72]

(a) Any source modification, construction, or reconstruction is governed by the applicable provisions of 326 IAC 2-7-10.5.

(b) Permit amendments and modifications are governed by the requirements of 326 IAC 2-7-11 or 326 IAC 2-7-12 whenever the Permittee seeks to amend or modify this permit.

(c) Pursuant to 326 IAC 2-7-11(b) and 326 IAC 2-7-12(a), administrative Part 70 permit amendments and permit modifications for purposes of the acid rain portion of a Part 70 permit shall be governed by regulations promulgated under Title IV of the Clean Air Act. [40 CFR 72]

(d) Any application requesting a source modification or an amendment or modification of this permit shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

Any such application shall be certified by the "responsible official" as defined by 326 IAC 2-7-1(34).

(e) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

C.5 Inspection and Entry [326 IAC 2-7-6]

Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee's right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a Part 70 source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this approval;

(b) Have access to and copy, at reasonable times, any records that must be kept under this title or the conditions of this approval or any operating permit revisions;

(c) Inspect, at reasonable times, any processes, emissions units (including monitoring and air pollution control equipment), practices, or operations regulated or required under this approval or any operating permit revisions;

(d) Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with this approval or applicable requirements; and

(e) Utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this approval or applicable requirements.

C.6 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

C.7 Fugitive Dust Emissions [326 IAC 6-4]

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

Testing Requirements [326 IAC 2-7-6(1)]

C.8 Performance Testing [326 IAC 3-6][326 IAC 2-1.1-11]

(a) Compliance testing on ABB CT No. 3 shall be conducted within 60 days after achieving maximum production rate, but no later than 180 days after initial start-up, as specified in Section D of this approval. All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this approval, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ.

A test protocol, except as provided elsewhere in this approval, shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ, within forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ, if the source submits to IDEM, OAQ, a reasonable written explanation within five (5) days prior to the end of the initial forty-five (45) day period.

Compliance Requirements [326 IAC 2-1.1-11]

C.9 Compliance Requirements [326 IAC 2-1.1-11]

The commissioner may require stack testing, monitoring, or reporting at any time to assure compliance with all applicable requirements. Any monitoring or testing shall be performed in accordance with 326 IAC 3 or other methods approved by the commissioner or the U. S. EPA.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)] [326 IAC 2-7-6(1)]

C.10 Compliance Monitoring [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

All monitoring and record keeping requirements shall be implemented when operation begins. The Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment.

C.11 Maintenance of Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) In the event that a breakdown of the emission monitoring equipment occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem. To the extent practicable, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less frequent than required in Section D of this permit until such time as the monitoring equipment is back in operation. In the case of continuous monitoring, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less often than once an hour until such time as the continuous monitor is back in operation.

(b) The Permittee shall install, calibrate, maintain, and operate all necessary monitors and related equipment. In addition, prompt corrective action shall be initiated whenever indicated.

C.12 Pressure Gauge and Other Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

(a) Whenever a condition in this permit requires the measurement of a flow rate, the instrument employed shall have a scale such that the expected normal reading shall be no less than twenty percent (20%) of full scale and be accurate within plus or minus two percent (±2%) of full scale reading.

(c) The Permittee may request the IDEM, OAQ approve the use of an instrument that does not meet the above specifications provided the Permittee can demonstrate an alternative instrument specification will adequately ensure compliance with permit conditions requiring the measurement of the flow rate.

Corrective Actions and Response Steps [326 IAC 2-7-5] [326 IAC 2-7-6]

C.13 Compliance Monitoring Plan - Failure to Take Response Steps [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) The Permittee is required to implement a compliance monitoring plan to ensure that reasonable information is available to evaluate its continuous compliance with applicable requirements. The compliance monitoring plan can be either an entirely new document, consist in whole of information contained in other documents, or consist of a combination of new information and information contained in other documents. If the compliance monitoring plan incorporates by reference information contained in other documents, the Permittee shall identify as part of the compliance monitoring plan the documents in which the information is found. The elements of the compliance monitoring plan are:

(1) This condition;

(2) The Compliance Determination Requirements in Section D of this permit;

(3) The Compliance Monitoring Requirements in Section D of this permit;

(4) The Record Keeping and Reporting Requirements in Section C (General Record Keeping Requirements, and General Reporting Requirements) and in Section D of this permit; and

(5) A Compliance Response Plan (CRP) for each compliance monitoring condition of this permit. CRP's shall be submitted to IDEM, OAQ upon request and shall be subject to review and approval by IDEM, OAQ. The CRP shall be prepared within ninety (90) days after issuance of this permit by the Permittee and maintained on site, and is comprised of:

(A) Reasonable response steps that may be implemented in the event that compliance related information indicates that a response step is needed pursuant to the requirements of Section D of this permit; and

(B) A time schedule for taking reasonable response steps including a schedule for devising additional response steps for situations that may not have been predicted.

(b) For each compliance monitoring condition of this permit, reasonable response steps shall be taken when indicated by the provisions of that compliance monitoring condition. Failure to take reasonable response steps may constitute a violation of the permit.

(c) Upon investigation of a compliance monitoring excursion, the Permittee is excused from taking further response steps for any of the following reasons:

(1) A false reading occurs due to the malfunction of the monitoring equipment. This shall be an excuse from taking further response steps providing that prompt action was taken to correct the monitoring equipment.

(2) The Permittee has determined that the compliance monitoring parameters established in the permit conditions are technically inappropriate, has previously submitted a request for an administrative amendment to the permit, and such request has not been denied.

(3) An automatic measurement was taken when the process was not operating.

(4) The process has already returned or is returning to operating within "normal" parameters and no response steps are required.

(d) Records shall be kept of all instances in which the compliance related information was not met and of all response steps taken. In the event of an emergency, the provisions of 326 IAC 2-7-16 (Emergency Provisions) requiring prompt corrective action to mitigate emissions shall prevail.

(e) All monitoring required in Section D shall be performed at all times the equipment is operating. If monitoring is required by Section D and the equipment is not operating, then the Permittee may record the fact that the equipment is not operating or perform the required monitoring.

(f) At its discretion, IDEM may excuse the Permittee's failure to perform the monitoring and record keeping as required by Section D, if the Permittee provides adequate justification and documents that such failures do not exceed five percent (5%) of the operating time in any quarter. Temporary, unscheduled unavailability of qualified staff shall be considered a valid reason for failure to perform the monitoring or record keeping requirements in Section D.

C.14 Emergency Provisions [326 IAC 2-7-16]

(a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation, except as provided in 326 IAC 2-7-16.

(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a health-based or technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:

(1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;

(2) The permitted facility was at the time being properly operated;

(3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance Section), or

Telephone Number: 317-233-5674 (ask for Compliance Section)
Facsimile Number: 317-233-5967.

(5) For each emergency lasting one (1) hour or more, the Permittee submitted the attached Emergency Occurrence Report Form or its equivalent, either by mail or facsimile to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

within two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-7-5(3)(C)(ii) and must contain the following:

(A) A description of the emergency;

(B) Any steps taken to mitigate the emissions; and

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(6) The Permittee immediately took all reasonable steps to correct the emergency.

(c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

(d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.

(e) IDEM, OAQ, may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4-(c)(10) be revised in response to an emergency.

(f) Failure to notify IDEM, OAQ, by telephone or facsimile of an emergency lasting more than one (1) hour in accordance with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-7 and any other applicable rules.

(g) Operations may continue during an emergency only if the following conditions are met:

(1) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

(2) If an emergency situation causes a deviation from a health-based limit, the Permittee may not continue to operate the affected emissions facilities unless:

(A) The Permittee immediately takes all reasonable steps to correct the emergency situation and to minimize emissions; and

(B) Continued operation of the facilities is necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value.

Any operation shall continue no longer than the minimum time required to prevent the situations identified in (g)(2)(B) of this condition.

C.15 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall take appropriate response actions. The Permittee shall submit a description of these response actions to IDEM, OAQ, within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize excess emissions from the affected facility while the response actions are being implemented.

(b) A retest to demonstrate compliance shall be performed within one hundred twenty (120) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ that retesting in one-hundred and twenty (120) days is not practicable, IDEM, OAQ may extend the retesting deadline.

(c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

The documents submitted pursuant to this condition do not require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19

C.16 NSPS Reporting Requirement [40 CFR 60.7]

Pursuant to the New Source Performance Standards (NSPS), Part 60.7, any owner or operator shall furnish the Administrator and IDEM written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

(a) Commencement of construction date (no later than 30 days after such date);

(b) Anticipated start-up date (not more than 60 days or less than 30 days prior to such date);

(c) Actual start-up date (within 15 days after such date); and

(d) Date of performance testing (at least 30 days prior to such date), when required by a condition elsewhere in this permit.

Reports are to be sent to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, IN 46206-6015

The application and enforcement of these standards have been delegated to the IDEM-OAQ. The requirements of 40 CFR Part 60 are also federally enforceable.

C.17 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]

(a) Records of all required data, reports and support information shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. These records shall be kept at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Unless otherwise specified in this permit, all record keeping requirements not already legally required shall be implemented when the new or modified equipment begins normal operation.

C.18 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11]

(a) The source shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported. This report shall be submitted within thirty (30) days of the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(b) The reports required by conditions in Section D of this permit shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ, on or before the date it is due.

(d) Unless otherwise specified in this permit, all reports required in Section D of this permit shall be submitted within thirty (30) days of the end of the reporting period. All reports do require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(e) The first report shall cover the period commencing on the date of issuance of this permit and ending on the last day of the reporting period. Reporting periods are based on calendar years.

Acid Rain Program

C.19 Title IV Emissions Allowances [326 IAC 2-7-5(4)] [326 IAC 21]

Emissions exceeding any allowances that the Permittee lawfully holds under the Title IV Acid Rain Program of the Clean Air Act are prohibited, subject to the following limitations:

(a) No revision of this permit shall be required for increases in emissions that are authorized by allowances acquired under the Title IV Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement.

(b) No limit shall be placed on the number of allowances held by the Permittee. The Permittee may not use allowances as a defense to noncompliance with any other applicable requirement.

(c) Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Clean Air Act.

SECTION D.1 FACILITY CONDITIONS

Facility Description [326 IAC 2-7-5(15)]:

One (1) existing simple-cycle, natural gas-fired combustion turbine, designated as unit ABB CT No. 3, with a maximum heat input capacity of 1110.9 MMBtu/hr (higher heating value (HHV) with natural gas fuel condition), a maximum output of 109 MW, and a nominal output of 80 MW, utilizing No. 2 distillate oil as a back-up fuel source (maximum heat input capacity of 1195.2 MMBtu/hr at HHV condition). NO_X emissions are controlled by dual fuel dry low-NO_X (DLN) combustors, with steam injection for additional NO_X reduction when firing distillate oil. Inlet fogging and steam augmentation may be used to enhance power production.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.1 Prevention of Significant Deterioration [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD), this modification is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of NO_X, CO, and PM_{10}, because the potential to emit for these pollutants exceed the PSD major significant thresholds. Therefore, the PSD provisions require that this modification be reviewed to ensure compliance with the National Ambient Air Quality Standards (NAAQS), the applicable PSD air quality increments, and the requirements to apply the Best Available Control Technology (BACT) for the affected pollutants.

(b) Conditions in this D section shall supersede Operation Conditions 2, 3, 4, 5, 6, 7, 8, 9, and 10 of Construction Permit CP067-10006-00065 issued December 7, 1998. This removes the operation restrictions that previously limited emissions from ABB CT No. 3 below PSD significant thresholds.

D.2 PSD Fuel Limits [40 CFR 52.21] [326 IAC 2-2]

Pursuant to 40 CFR 52.21 (Prevention of Significant Deterioration of Air Quality) and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD) Requirements),

(a) The maximum heat input capacity of ABB CT No. 3 at 0EF is 1110.9 MMBtu/hr (higher heating value (HHV)) when firing natural gas.

(b) The maximum heat input capacity of ABB CT No. 3 at 0EF is 1195.2 MMBtu/hr (HHV) when firing No. 2 distillate oil.

(c) The input of distillate oil shall not exceed 4268.57 thousand gallons (kgal) per twelve (12) consecutive month period.

D.3 Startup/Shutdown Limits [40 CFR 52.21] [326 IAC 2-2]

(a) Startup is defined as the period of time from the initiation of combustion firing from a "cold start" operating condition to the attainment of steady-state operating condition.

(b) Shutdown is defined as that period of time from the initial lowering of the turbine output to the complete cessation of fuel combustion in the unit with the intent to shutdown to a "cold stop" condition.

(c) A startup/shutdown cycle is a pair of subsequent shutdown and startup events (i.e., one startup followed by one shutdown represents one startup/shutdown cycle).

(d) Pursuant to 326 IAC 2-2 (PSD Requirements), ABB CT No. 3 shall meet the following startup and shutdown limits:

(1) The maximum number of startup/shutdown cycles shall not exceed 240 per 12 consecutive months period rolled on monthly basis as determined at the end of each calendar month. The duration of each startup/shutdown cycle shall not exceed one (1) hour.

(2) When firing natural gas:

(A) The NO_X emissions shall not exceed 36 pounds per each startup/shutdown cycle.

(B) The CO emissions shall not exceed 60 pounds per each startup/shutdown cycle.

(3) When firing distillate oil:

(A) The NO_X emissions shall not exceed 180 pounds per each startup/shutdown cycle.

(B) The CO emissions shall not exceed 61 pounds per each startup/shutdown cycle.

D.4 PSD Nitrogen Oxides (NOx) - BACT Limits [40 CFR 52.21] [326 IAC 2-2-3]

(a) Pursuant to 40 CFR 52.21 and 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), ABB CT No. 3 shall comply with the following when firing natural gas:

(1) Use of Dry Low-NO_X combustors at all times.

(2) Except during periods of startups and shutdowns, the NO_X emission rate when firing natural gas shall not exceed nine (9) parts per million on a volume dry basis (ppmvd) corrected to 15 percent O_2, averaged over a 24 operating hour period. This is equivalent to 36 pounds of NO_X per hour at the maximum fuel heat input condition.

(b) Pursuant to 40 CFR 52.21 and 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), ABB CT No. 3 shall comply with the following when firing distillate oil:

(1) Use of Dry Low-NO_X combustors at all times.

(2) Use of steam injection at all times; the maximum steam injection rate is 80,000 pounds per hour of 400 psig and 560° F steam, which is equivalent to a steam - to - fuel ratio of 1.3 at the maximum fuel input operating condition of 0° F.

(3) Except during periods of startups and shutdowns, the NO_X emission rate when firing distillate oil shall not exceed a twenty-four (24) hour average concentration of 42 ppmvd corrected to 15 percent O_2. This is equivalent to 180 pounds of NO_X per hour at the maximum fuel heat input condition.

(c) Annual NO_X emissions, excluding startup and shutdown emissions, shall not exceed 132.06 tons per twelve (12) consecutive month period.

D.5 PSD Carbon Monoxide (CO) - BACT Limits [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), ABB CT No. 3 shall comply with the following:

(a) Except during periods of startups and shutdowns, the CO emission rate shall not exceed a twenty-four (24) hour average concentration of 25 ppmvd corrected to 15 percent O_2.

(1) When firing natural gas, this is equivalent to 60 pounds of CO per hour at the maximum heat input condition.

(2) When firing distillate oil, this is equivalent to 61 pounds of CO per hour at the maximum fuel heat input condition.

(b) Perform good combustion practices to minimize CO emissions.

(c) Annual CO emissions, excluding startup and shutdown emissions, shall not exceed 221.52 tons per twelve (12) consecutive month period.

D.6 Particulate Matter (PM_{10}) - BACT Limits [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), ABB CT No. 3 shall comply with the following:

(a) Use of natural gas as primary fuel;

(b) The use of No. 2 distillate oil as a back-up fuel, limited to not more than 4268.57 thousand gallons (kgal) per twelve (12) consecutive month period;

(c) Except during periods of startups and shutdowns, the PM_{10} emission rate shall not exceed:

(1) 0.0045 lb/MMBtu when firing natural gas, which is equivalent to 5.0 pounds per hour of PM_{10}.

(2) 0.0083 lb/MMBtu when firing distillate oil, which is equivalent to 10.0 pounds per hour of PM_{10}.

(d) Perform good combustion practices to minimize PM_{10} emissions.

(e) Annual PM_{10} emissions, including startup and shutdown emissions, shall not exceed 21.9 tons per twelve (12) consecutive month period.

(f) The total PM_{10} is the sum of filterable and condensible PM_{10}.

D.7 Opacity Limit [40 CFR 52.21][326 IAC 2-2]

Pursuant to Construction Permit PC (65) 1802 issued November 6, 1999, and 40 CFR 52.21 and 326 IAC 2-2 (PSD Requirements) the opacity from the associated combustion turbine stack shall not exceed twenty (20) percent (6-minute average). This satisfies the opacity limitations required by 326 IAC 5-1 (Opacity Limitations).

D.8 Fuel Sulfur Content Limitations [40 CFR 52.21] [326 IAC 2-2]

(a) The sulfur content of the natural gas fuel shall not exceed 0.0056 percent (%) by weight.

(b) The sulfur content of the distillate oil fuel shall not exceed 0.05 percent (%) by weight.

Compliance with these restrictions limits the sulfur dioxide emissions from ABB CT No. 3 to less than 40 tons per year. Therefore, PSD BACT requirements do not apply to the SO_2 emissions.

D.9 Sulfur Dioxide Emission Limitations [326 IAC 7-1]

Pursuant to 326 IAC 7-1.1-2, the sulfur dioxide emissions from the turbine shall be limited to 0.5 pounds per million Btu when firing distillate oil, the backup fuel.

D.10 40 CFR Part 60, Subpart GG (Stationary Gas Turbines) [326 IAC 12-1]

(a) When firing natural gas, the combustion turbine ABB CT No. 3 is subject to 40 CFR Part 60, Subpart GG because it is a gas-fired turbine and the heat input at peak load is equal to or greater than 10.7 gigajoules per hour (10 MMBtu per hour), based on the lower heating value of the fuel fired.

(b) Pursuant to 326 IAC 12-1 and 40 CFR 60, Subpart GG (Stationary Gas Turbines), the Permittee shall:

(1) limit nitrogen oxides emissions, as required by 40 CFR 60.332(a)(1), to:

$$STD = 0.0075 \frac{(14.4)}{Y} + F,$$

where STD = allowable NO_X emissions (percent by volume at 15 percent oxygen on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

(2) limit sulfur dioxide emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at 15 percent oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to 0.8 percent by weight.

D.11 Formaldehyde Limit [326 IAC 2-1.1-5] [326 IAC 2-4.1-1]

Pursuant to 326 IAC 2-4.1-1 (New Source Toxics Control), the formaldehyde emissions from ABB CT No. 3 shall not exceed 0.00071 lb/MMBtu. This will limit the combined formaldehyde emissions from ABB CT No. 3 and ABB CT No.4 to less than 10 tons per year; therefore, the requirements of 326 IAC 2-4.1 are not applicable.

D.12 General Provisions Relating to NSPS [326 IAC 12-1] [40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR Part 60, Subpart GG.

D.13 Preventive Maintenance Plan [326 IAC 1-6-3]

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this approval, is required for this facility.

Compliance Determination Requirements

D.14 Continuous Emission Monitoring System (CEMS) [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5-1(d)(1), the owner or operator of this air emission source permitted under 326 IAC 2-2 and 326 IAC 2-7 shall be required to install a continuous emissions monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5.

(b) For NO_X and CO, the Permittee shall install, calibrate, certify, operate and maintain a continuous emissions monitoring system for the CT No. 3 stack in accordance with 326 IAC 3-5-2 through 326 IAC 3-5-7

(1) The continuous emissions monitoring system (CEMS) shall measure NO_X and CO emissions rates in pounds per hour and parts per million (ppmvd). The use of CEMS to measure and record the NO_X and CO hourly emission rates is sufficient to demonstrate compliance with the limits established in the BACT analyses. To demonstrate compliance with the NO_X limit, the source shall take an average of the parts per million (ppm) over a twenty-four (24) operating hour period. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppm) over a twenty-four (24)-hour period. The source shall maintain records of the parts per million and the pounds per hour.

(2) The Permittee shall determine compliance with the Startup/Shutdown Limits (Condition D.3) utilizing data from the NO_X, CO, and CO_2 or O_2 CEMS, and the fuel flow meter, and Method 19 calculations.

(2) The Permittee shall submit to IDEM, OAQ, within ninety (90) days after monitor installation, a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4.

(3) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7.

(4) The source shall maintain records of the amount of natural gas combusted and the amount of distillate oil combusted in ABB CT No. 3 on a monthly basis.

(5) In instances of downtime, the source shall use the Missing Data Substitution Procedures outlined in 40 CFR Part 75, Subpart D to demonstrate compliance with the NO_X limit, established under the NO_X BACT Limits condition (Condition D.4), and shall use the manufacturer's guaranteed emission rate to demonstrate compliance with the CO limit established under the CO BACT Limits condition (Condition D.5).

(6) The source may submit to the OAQ alternative emission factors based on the source's CEMS data (collected over a period of twelve (12) consecutive months) and the corresponding site temperatures, to use in lieu of the manufacturer's guaranteed emission rates in instances of downtime. The alternative emissions factors must be approved by the OAQ prior to use in calculating emissions for the limitations established in this approval. The alternative emission factors shall be based upon collected monitoring and test data supplied from an approved continuous emissions monitoring system. In the event that the information submitted does not contain sufficient data to establish appropriate emission factors, the source shall continue to collect data until appropriate emission factors can be established. During this period of time, the source shall continue to use the manufacturer's guaranteed emission rate for CO compliance determination and use the NO_X Missing Data Substitution Procedures specified in 40 CFR Part 75, Subpart D for NO_X compliance determination, in periods of downtime.

(c) The Permittee shall follow parametric monitoring requirements for determining SO_2 emissions contained in the "*Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units"* in lieu of continuous emissions monitoring systems (CEMS).

(1) Pursuant to the procedures contained in 40 CFR 75.20, the Permittee shall complete all testing requirements to certify the use of the *"Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units"*.

(2) The Permittee shall apply to IDEM for initial certification to use the *"Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units"* , no later than 45 days after the compliance of all certification tests.

(3) All certification and compliance methods shall be conducted in accordance with the procedures outlined in 40 CFR Part 75, Appendix D.

D.15 Testing Requirements [326 IAC 3-5] [326 IAC 2-1.1-5] [40 CFR Part 60, Subpart GG]

(a) Pursuant to 326 IAC 3-5, the Permittee shall conduct a performance test on the combustion turbine CT No. 3 exhaust stack not later than one-hundred and eighty (180) days after initial start-up in order to certify the continuous emissions monitoring systems for NO_X and CO. These tests shall be performed in accordance with Section C – Performance Testing.

(b) Pursuant to 40 CFR Part 60, Subpart GG (Stationary Gas Turbines) and 326 IAC 12-1, within sixty (60) days after achieving maximum production rate, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall determine the NO_X, SO_2, and diluent emissions from the turbine ABB CT No. 3 exhaust stack, in accordance with 40 CFR 60.335 and Section C – Performance Testing, in order to document compliance with the Subpart GG NO_X and SO_2 limits in Condition D.10(b).

(c) Pursuant to 326 IAC 2-1.1-5, within one hundred and eighty (180) days after initial startup, the Permittee shall perform formaldehyde stack test on the CT No. 3 exhaust stack utilizing a method approved by the Commissioner when operating at 50%, 75%, and 100% load. These tests shall be performed in accordance with Section C – Performance Testing, in order to determine compliance with the Formaldehyde limit in Condition D.11.

D.16 40 CFR Part 60, Subpart GG (Stationary Gas Turbines) Compliance Requirements [326 IAC 12-1]

Pursuant to 40 CFR Part 60, Subpart GG (Stationary Gas Turbines), the Permittee shall monitor the nitrogen and sulfur content of the natural gas on a daily basis as follows:

(a) Determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a), per the requirements described in 40 CFR 60.335(c);

(b) Determine the sulfur content of the natural gas being fired in the turbine by ASTM methods D 1072-80, D 3031-81, D 4084-82, or D 3246-81. The applicable ranges of some ASTM methods mentioned are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator; and

(c) Determine the nitrogen content of the natural gas being fired in the turbine by using analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator.

The analyses required above may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor or any other qualified agency.

Owners, operators or fuel vendors may develop custom schedules for determination of the nitrogen and sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with the above requirements.

D.17 Alternative Sulfur Content Monitoring [40 CFR 60.334(b)(2)]

Pursuant to 40 CFR 60.334(b)(2) and the IDEM approval, issued on July 6, 1995, the Permittee may use the following schedule for monitoring sulfur content in lieu of the sulfur content determination requirements of 40 CFR Part 60, Subpart GG:

(a) The Permittee agrees to use sulfur analyses from the supplier certifications for the natural gas, provided the gas samples are taken once per quarter at the closest available proximity to the A.B. Brown Station.

(b) In the event of less than 30 days of turbine operation in a quarter, the quarterly sampling requirement is waived. For these purposes, one day of operation will be defined as any day that natural gas is burned for more than one hour.

(c) Quarterly sampling and analysis of the natural gas shall be performed according to the ASTM methods detailed in 60.335(d).

D.18 Sulfur Dioxide Compliance and Reporting Requirements [326 IAC 7-2-1] [326 IAC 2-2-3]

(a) Pursuant to 326 IAC 7-2-1, owners or operators of sources or facilities subject to 326 IAC 7-1.1 shall submit to the Commissioner reports of calendar month average sulfur content, heat content, fuel consumption, and sulfur dioxide emission rate in pounds per million Btus upon request. The reports shall be based on fuel sampling and analysis data in accordance with procedures specified under 326 IAC 3-3.

(b) Pursuant to 326 IAC 2-2-3, the Permittee shall demonstrate that the fuel oil sulfur content does not exceed 0.05 percent by weight by one of the following methods:

(1) Fuel sampling and analysis data shall be collected pursuant to the procedures specified in 326 IAC 3-7-4 for oil combustion. Computation of calculated sulfur dioxide emission rates from fuel sampling and analysis data shall be based on the emission factors contained in U.S. EPA publication AP-42, “Compilation of Air Pollutant Emission Factors”, unless other emission factors based on site-specific sulfur dioxide measurements are approved by the commissioner and the U.S. EPA. Compliance or noncompliance shall be determined using a calendar month average sulfur dioxide emission rate in pounds per million Btus.

or

(2) Compliance or noncompliance may be determined by conducting a stack test for sulfur dioxide emissions from the combustion turbine, in accordance with the procedures in 326 IAC 3-6 utilizing procedures outlined in 40 CFR 60, Appendix A, Method 6.

(c) A determination of noncompliance pursuant to either of the methods specified in (b)(1) or (b)(2) above shall not be refuted by evidence of compliance pursuant to the other method.

(d) Upon written notification of a facility owner or operator to the department, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance.

Compliance Monitoring Requirements

D.19 Visible Emissions Notations

(a) When fuel oil is being fired, visible emission notations of the CT No. 3 stack exhaust shall be performed during normal daylight operations at least once every 24 hours of fuel oil use. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

(e) The Compliance Response Plan for this unit shall contain troubleshooting contingency and response steps for when an abnormal emission is observed.

Record Keeping and Reporting Requirements [326 IAC 2-1-3]

D.20 Record Keeping Requirements

(a) To document compliance with Condition D.2, the Permittee shall maintain records of the following:

(1) Amount of natural gas combusted (in MMCF) in the turbine during each month.

(2) Amount of distillate oil combusted (in kgal) in the turbine during each month.

(3) The average heat content, on a higher heating value basis, of the natural gas combusted each month.

(4) The average heat content, on a higher heating value basis, of the distillate oil combusted each month, if any.

(b) To document compliance with Conditions D.6, D.8, D.10, and D.18, the source shall maintain records of the natural gas analyses, including the sulfur and nitrogen content of the gas, for a period of three (3) years. If Condition D.17 is used to monitor sulfur content, these records shall include:

(1) The results of the sulfur content analyses contained in the supplier certifications.

(2) The location where the samples were taken.

(c) To document compliance with Conditions D.6, D.8, D.10, and D.18, the source shall maintain records of the distillate oil analyses, including the sulfur content of the oil, for a period of three (3) years.

(b) To document compliance with Condition D.4 and D.5, the Permittee shall record the emission rates of NOx and CO in pounds per hour and parts per million (ppmvd) corrected to 15 percent O_2.

(c) To document compliance with Condition D.3 , the Permittee shall maintain records of the following:

(1) The type of operation (i.e., startup or shutdown) with supporting operational data.

(2) The total number of minutes for startup or shutdown per 24-hour period per turbine.

(3) The CEMS data and fuel flow meter data corresponding to each startup and shutdown period.

(d) To document compliance with D.14, the Permittee shall maintain records, including raw data of all monitoring data and supporting information, for a minimum of five (5) years from the date as described in 326 IAC 3-5-7(a). The records shall include the information described in 326 IAC 3-5-7(b).

(e) To document compliance with Condition D.19, the Permittee shall maintain records of the visible emission notations of the CT No. 3 stack exhaust when firing distillate oil.

(f) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this approval.

D.21 Reporting Requirements

(a) The Permittee shall submit the following information on a quarterly basis:

(1) Records of excess NO_X and CO emissions (defined in 326 IAC 3-5-7 and 40 CFR Part 60.7) from the continuous emissions monitoring system. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C – General Reporting Requirements of this permit.

(2) The Permittee shall report periods of excess emissions, as required by 40 CFR 60.334(c).

(3) A quarterly summary of the CEMs data to document compliance with D.4 and D.5 shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported.

(4) A quarterly summary of the total number of startup/shutdown cycles to document compliance with Condition D.3, shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported.

(5) For any quarter in which distillate oil is fired, a quarterly summary of the volume of distillate oil input to Unit 3 to document compliance with Condition D.2(c), shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported. For quarters in which no distillate oil is fired, the source does not need to submit a distillate oil usage report form; the fact that no oil was used will be reported on the semi-annual natural gas fired unit certification form.

(b) The Permittee shall submit the following information on a semi-annual basis:

(1) A certification, signed by the responsible official, that certifies all of the fuels combusted during the period. The natural gas-fired facility certification does require the certification by the responsible official as defined by 326 IAC 2-7-1(34);

(2) The natural gas fired facility certification shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the six (6) month period being reported.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

PART 70 SOURCE MODIFICATION CERTIFICATION

Source Name:	Southern Indiana Gas and Electric Company (SIGECO) - A. B. Brown Station
Source Address:	W. Franklin Road and Welborn Road, West Franklin, Indiana 47620
Mailing Address:	P. O. Box 3606, Evansville, Indiana, 47735-3606
Permit No.:	SSM 129-12029-00010

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this approval.

Please check what document is being certified:

9 Test Result (specify) ________________________________

9 Report (specify) ________________________________

9 Notification (specify) ________________________________

9 Affidavit (specify) ________________________________

9 Other (specify) ________________________________

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:
Printed Name:
Title/Position:
Date:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY

COMPLIANCE BRANCH
100 North Senate Avenue
P.O. Box 6015
Indianapolis, Indiana 46206-6015
Phone: 317-233-5674
Fax: 317-233-5967

PART 70 SOURCE MODIFICATION
EMERGENCY OCCURRENCE REPORT

Source Name: Southern Indiana Gas and Electric Company (SIGECO) - A. B. Brown Station
Source Address: W. Franklin Road and Welborn Road, West Franklin, Indiana 47620
Mailing Address: P. O. Box 3606, Evansville, Indiana, 47735-3606
Permit No.: SSM 129-12029-00010

This form consists of 2 pages **Page 1 of 2**

9 This is an emergency as defined in 326 IAC 2-7-1(12) C The Permittee must notify the Office of Air Quality (OAQ), within four (**4**) business hours (1-800-451-6027 or 317-233-5674, ask for Compliance Section); and C The Permittee must submit notice in writing or by facsimile within two (**2**) days (Facsimile Number: 317-233-5967), and follow the other requirements of 326 IAC 2-7-16.

If any of the following are not applicable, mark N/A

Facility/Equipment/Operation:
Control Equipment:
Permit Condition or Operation Limitation in Permit:
Description of the Emergency:
Describe the cause of the Emergency:

If any of the following are not applicable, mark N/A **Page 2 of 2**

Date/Time Emergency started:
Date/Time Emergency was corrected:
Was the facility being properly operated at the time of the emergency? Y N Describe:
Type of Pollutants Emitted: TSP, PM-10, SO_2, VOC, NO_X, CO, Pb, other:
Estimated amount of pollutant(s) emitted during emergency:
Describe the steps taken to mitigate the problem:
Describe the corrective actions/response steps taken:
Describe the measures taken to minimize emissions:
If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:

Form Completed by: ____________________

Title / Position: ____________________

Date: ____________________

Phone: ____________________

A certification is not required for this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY

COMPLIANCE DATA SECTION
100 North Senate Avenue
P.O. Box 6015
Indianapolis, Indiana 46206-6015
Phone: 317-233-5674
Fax: 317-233-5967

PART 70 SOURCE MODIFICATION
STARTUP/SHUTDOWN CYCLES - QUARTERLY REPORT

Source Name: Southern Indiana Gas and Electric Company (SIGECO) - A. B. Brown Station
Source Address: W. Franklin Road and Welborn Road, West Franklin, Indiana 47620
Mailing Address: P. O. Box 3606, Evansville, Indiana, 47735-3606
Permit No.: SSM 129-12029-00010
Unit: ABB CT No. 3
Limit: Shall not exceed 240 startup/shutdown cycles per year;
the time for each startup/shutdown cycle shall not exceed one (1) hour.

Month: ____________________ **Year:** ________________________

Total number of startups from previous eleven (11) month(s): _________________

Total number of startups for most recent twelve (12) month period: _________________

Day	Number of Startups	Day	Number of Startups	Day	Number of Startups
1		12		23	
2		13		24	
3		14		25	
4		15		26	
5		16		27	
6		17		28	
7		18		29	
8		19		30	
9		20		31	
10		21			
11		22		TOTAL:	

9 No deviation occurred in this month 9 Deviation(s) occurred in this month.

Deviation has been reported on: ___________________________________

Submitted by: ____

Title/Position: ____

Signature: ____

Date: ____

Phone: ____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR MANAGEMENT
COMPLIANCE DATA SECTION

PART 70 OPERATING PERMIT
NATURAL GAS FIRED UNIT CERTIFICATION

Source Name: Southern Indiana Gas and Electric Company (SIGECO) - A. B. Brown Station
Source Address: W. Franklin Road and Welborn Road, West Franklin, Indiana 47620
Mailing Address: P. O. Box 3606, Evansville, Indiana, 47735-3606
Permit No.: SSM 129-12029-00010

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Report period
Beginning: ____
Ending: ____

Unit Affected: CT No. 3	Alternate Fuel	Days burning alternate fuel From	To

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:
Printed Name:
Title/Position:
Date:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION
100 North Senate Avenue
P.O. Box 6015
Indianapolis, Indiana 46206-6015
Phone: 317-233-5674
Fax: 317-233-5967

PART 70 SOURCE MODIFICATION

Distillate Oil Usage - Quarterly Report

Source Name: Southern Indiana Gas and Electric Company (SIGECO) - A. B. Brown Station
Source Address: W. Franklin Road and Welborn Road, West Franklin, Indiana 47620
Mailing Address: P. O. Box 3606, Evansville, Indiana, 47735-3606
Permit No.: SSM 129-12029-00010
Unit: combustion turbine ABB CT No. 3
Limit: The input of distillate oil shall not exceed 4268.57 thousand gallons (kgal) per twelve (12) consecutive month period.

Year: ____________

Month	Distillate Oil Usage (kgal/month)	Usage for previous eleven month(s) (kgal)	Usage for twelve month period (kgal)

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on: ______________________

Submitted by: ____

Title / Position: ____

Signature: ____

Date: ____

Phone: ____

Mail to: Permit Administration & Development Section
Office of Air Quality
100 North Senate Avenue
P. O. Box 6015
Indianapolis, Indiana 46206-6015

Southern Indiana Gas and Electric Company
P. O. Box 3606
Evansville, Indiana, 47735-3606

Affidavit of Construction

I, ______________________________, being duly sworn upon my oath, depose and say:
(Name of the Authorized Representative)

1. I live in ____________________ County, Indiana and being of sound mind and over twenty-one (21) years of age, I am competent to give this affidavit.

2. I hold the position of ____________________ for ____________________.
(Title) (Company Name)

3. By virtue of my position with ______________________________, I have personal
(Company Name)

knowledge of the representations contained in this affidavit and am authorized to make these

representations on behalf of ______________________________ .
(Company Name)

4. I hereby certify that Southern Indiana Gas and Electric Company (SIGECO) - A. B. Brown Station, W. Franklin Road and Welborn Road, West Franklin, Indiana), completed modification of the combustion turbine identified as CT No. 3 on ______________in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality on March 13, 2000 and as permitted pursuant to **Significant Source Modification No. PSD 129-12029, Plant ID No. 129-00010** issued on ________________ .

5. Additional (?operations/facilities) were constructed/substituted as described in the attachment to this document and were not made in accordance with the construction permit. (Delete this statement if it does not apply.)

6. I hereby certify that SIGECO A.B. Brown Station remains subject to the Title V program .

Further Affiant said not.
I affirm under penalties of perjury that the representations contained in this affidavit are true, to the best of my information and belief.

____
Signature

____
Date

STATE OF INDIANA)
)SS

COUNTY OF __________________)

Subscribed and sworn to me, a notary public in and for __________________ County and State of Indiana

on this ____________ day of ______________, 20 ________ .

My Commission expires: ________________

____
Signature

____
Name (typed or printed)

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the
Technical Support Document for a Significant Source Modification

Source Name:	Southern Indiana Gas and Electric Company (SIGECO) A. B. Brown Generating Station
Source Location:	W. Franklin Road & Welborn Road, West Franklin, Indiana 47620
County:	Posey
SIC Code:	4911
Significant Source Modification No.:	129-12029-00010
Permit Reviewer:	Vickie Cordell

On September 26, 2001, the Office of Air Quality (OAQ) had a notice published in the Mount Vernon Democrat, Mount Vernon, Indiana, stating that Southern Indiana Gas and Electric Company (SIGECO), A. B. Brown Generating Station, had applied for approval to modify and operate one (1) existing simple-cycle, natural gas-fired combustion turbine, designated as unit ABB CT No. 3. The public notice also stated that OAQ proposed to issue the source modification for this operation and provided information on how the public could review the proposed approval and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

Comments were received from Stephen Loeschner on October 22, 2001 and from SIGECO on October 26, 2001. In the responses, additions to the permit are bolded for emphasis; the language with a line through it has been deleted.

Mr. Loeschner submitted the following comments on the proposed source modification 129-12029-00010 and on 129-14021-00010, another proposed Significant Source Modification that was on public notice at the same time for the addition of an entirely new combustion turbine at the same source.

Comment 1:

Scattered throughout the drafts and the Duke Knox County 083-12674-00043 issued PSD permit package ("12674") are four nominal billion BTU / hour heat rate values: 1.1109, 1.1458, 1.158, and 1.1952. In the interest of simplicity, my comment generally ignores those variations. DEM is free to introduce the appropriate factors, but if introduced, they must be applied to all; as in some places they would favor the People, while in others, they would favor SIGECO.

Response to Comment 1:

The heat input capacity of a combustion unit is not a fixed number. It is dependent on the heat content of the fuel being fired and the effective temperature of the air fed to the combustion chamber. The maximum heat input capacity for A.B. Brown Unit 3 at 0^oF is 1110.9 million Btus per hour (MMBtu/hr) when firing natural gas and 1195.2 MMBtu/hr when firing distillate oil. (MMBtu is used as the unit of heat input to be consistent with the EPA emission factors for combustion turbines, which are stated in pounds of pollutant per MMBtu.) The maximum heat input capacity for Unit 4 at ^0F is 1145.8 MMBtu/hr. It is not unexpected to have a slight difference between Unit 3 and Unit 4 since Unit 4 is a totally new turbine and Unit 3 is an existing turbine that is being retrofit with dry-low NOx (DLN) combustion technology and replacement of other hot gas pathway components. The heat input capacity for each of the Duke Knox units at 53^oF is 1158 MMBtu/hr.

The heat input capacity at 0°F was used for the A.B. Brown permits due to the inclusion of power augmentation for the A.B. Brown turbines. The augmentation includes steam injection and inlet fogging. The higher capacities were used to provide a conservative estimate of the emissions with the use of power augmentation, which simulates lower ambient temperatures in the combustion zone. Use of the highest heat input capacity in calculating the maximum annual emissions ensures that the highest possible emissions are used in the modeling analysis while eliminating the need for any limit or record keeping on the use of the power augmentation.

Comment 2:

12029 D.4(a)(2), 14021 D.1.4(a)(2), and 12674 D.1.5(a)(3) each have a 9 part per million NOx by volume at 15% O2 on a dry basis ("ppmvd @ 15% O2") limit and corresponding verification requirements: 12029 D.14(b)(1), 14021 D.1.11(b)(1), and 12674 D.1.18(b)(1) for gas operation. The latter, in combination with the former, seem to bound the concentration, but the maximum amount seems unbounded.

12029 D.4(a)(2), 14021 D.1.4(a)(2), and 12674 D.1.5(a)(3) each have 36, 36, and 31.96 respectively pounds NOx per turbine / hour "equivalents" for gas operation. It is in no way clear that 12029 D.14(b)(1), 14021 D.1.11(b)(1), or 12674 D.1.18(b)(1) impose the former as enforceable limits. People have some mental grasp of what a pound of pollutant is. They have far less of a clue as to what ppmvd NOx @ 15% O2 is. Therefore, an enforceable short-term 24-hour average rolled hourly (counting only the hours operated) pounds NOx / hour limit must be added to the texts of the drafts. Further, given the similarity of the equipment, the imposed 12029 and 14021 gas operation enforceable limits must not exceed the 12674 31.96 pounds NOx / hour value absent substantial technical cause shown. And, the imposed 12029 oil operation enforceable limit must not exceed the 12674 166.98 pounds NOx / hour value absent substantial technical cause shown.

Response to Comment 2:

12029 D.3 and D.4, 14021 D.1.3 and D.1.4, and 12674 D.1.4 and D.1.5 include enforceable limits on the pounds of NOx per startup/shutdown cycle, the parts per million (ppm) and pounds per hour NOx emission rates during steady-state operation, and the annual NOx emissions. The Continuous Emission Monitoring System conditions, 12029 D.14(b)(1), 14021 D.1.11(b)(1), and 12674 D.1.18(b)(1), do not impose any limits; these conditions give requirements for the use of the continuous emission monitoring systems. Data recorded by the continuous emission monitors will be used to demonstrate compliance with the limits. The maximum hourly emissions are already provided in the pounds per hour format requested.

Like the heat input capacity, the emission rates in pounds per hour for a combustion unit are temperature dependent. The heat input capacity and the emissions in pounds per hour are higher at lower ambient temperatures, when the air is most dense. The steady-state emissions in ppm are consistent across all ambient temperature ranges.

The short-term NOx limit when firing natural gas, 9 parts per million (ppm), is the same for all three of the permits mentioned. The short-term NOx limit when firing distillate oil, 42 parts per million (ppm), is the same in 12029 and in 12674. The difference in the hourly NOx emission rates in the Duke Knox permit, 12674, and the draft permits for the A.B. Brown turbine projects is primarily due to the different ambient temperatures selected as most representative for each project. The TSD for permit 12674 states that the hourly NOx and CO emission rates are based on the average site temperature of 53°F. The applications for the A.B. Brown projects provided hourly NOx and CO emission rates at several ambient operating temperatures. At 60°F, the 9 ppm NOx limit for A.B. Brown Units 3 and 4 when firing natural gas is equivalent to 31 pounds per hour of NOx per unit, and the 12029 limit of 42 ppm NOx when firing distillate oil is equivalent to 156 pounds per hour. Each of these is comparable to the the hourly emission rate in the Duke NOx permit.

To further illustrate the emission variability due to air temperature, the following table shows the steady-state NOx and CO specifications provided by the turbine vendor for the retrofit of ABB CT No. 3.

ABB No. 3 CT DLN Conversion Air Emission Specifications					
Fuel Condition: NG					
Ambient operating temperature, ºF	**0**	**25**	**60**	**80**	**100**
Operating load	Base	Base	Base	Base	Base
PM, #/hr	5.0	5.0	5.0	5.0	5.0
NO_X, ppmvd @ 15% O_2	9	9	9	9	9
NO_X (as NO_2), #/hr	36	34	31	30	28
CO, ppmvd	25	25	25	25	25
CO, #/hr	60	57	52	49	46
Fuel Condition: DO					
PM, #/hr	10.0	10.0	10.0	10.0	10.0
NO_X, ppmvd @ 15% O_2	42	42	42	42	42
NO_X (as NO_2), #/hr	180	172	156	148	138
CO, ppmvd	25	25	25	25	25
CO, #/hr	61	57	53	50	47

Comment 3:

An additional matter is the fact that there are to be enforceable longer-term averaging limits, and sources are expected to perform better, on average, in those longer terms. 14021 D.1.4(b) has a 133.92 tons per year (“tpy”) NOx “equivalent”, but there seems no text that obligates compliance. It would lead to a calculated annual average of: 133.92 x 2,000 / 8,768 = 30.55 pounds NOx / hour.

Therefore, an enforceable long-term annual average rolled daily (counting only the days operated) NOx tpy gas operation limit of 133.92 tpy must be added to the text of the drafts.

Response to Comment 3:

Condition D.4(c) in 12029 and Condition D.1.4(b) in 14021 limit the total NOx emissions per 12 consecutive month period for steady-state operation. These are limits, not “equivalents”. The Reporting Requirements conditions, D.21 in 12029 and D.1.13 in 14021, require a quarterly summary of the CEMs data to document compliance with Conditions D.4 and D.1.4, respectively. That reporting requirement includes the annual NOx limits.

Upon further review, it has been determined that the annual NOx limits for 12029 and for 14021 should be based on the hourly emissions when firing natural gas at 60°F average ambient operating temperature. At 60°F, the hourly emission rate for 12029 and 14021 is 31 lbs/hr of NOx when firing natural gas. A maximum of 240 hours per year are allowed for startup and shutdown. Therefore, the annual emission limits for steady state operation are derived using 8,520 hours/year. (8,760 hours/ year - 240 hours/year = 8,520 hours/year). This results in allowable emissions of 132.06 tons of NOx per twelve consecutive month period for each turbine, excluding startup and shutdown.

The following conditions have been revised as shown. In Permit 14021 Condition D.1.4, the movement of the wording “excluding startup and shutdown emissions” also clarifies that Unit 4 does not have separate burners for startup; the unit will use dry low-NO_X combustors in conjunction with natural gas at all times.

Permit 029-12029-00010 revisions:

D.4 PSD Nitrogen Oxides (NOx) - BACT Limits [40 CFR 52.21] [326 IAC 2-2-3]

(a) Pursuant to 40 CFR 52.21 and 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), ABB CT No. 3 shall comply with the following when firing natural gas:

(1) Use of Dry Low-NO_X combustors at all times.

(2) Except during periods of startups and shutdowns, the NO_X emission rate when firing natural gas shall not exceed nine (9) parts per million on a volume dry basis (ppmvd) corrected to 15 percent O_2, averaged over a 24 operating hour period. This is equivalent to 36 pounds of NO_X per hour at the maximum fuel heat input condition.

(b) Pursuant to 40 CFR 52.21 and 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), ABB CT No. 3 shall comply with the following when firing distillate oil:

(1) Use of Dry Low-NO_X combustors at all times.

(2) Use of steam injection at all times; the maximum steam injection rate is 80,000 pounds per hour of 400 psig and 560° F steam, which is equivalent to a steam - to - fuel ratio of 1.3 at the maximum fuel input operating condition of 0° F.

(3) Except during periods of startups and shutdowns, the NO_X emission rate when firing distillate oil shall not exceed a twenty-four (24) hour average concentration of 42 ppmvd corrected to 15 percent O_2. This is equivalent to 180 pounds of NO_X per hour at the maximum fuel heat input condition.

(c) Annual NO_X emissions, ~~including~~ **excluding** startup and shutdown emissions, shall not exceed ~~193.68~~ **132.06** tons per twelve (12) consecutive month period.

Permit 029-14021-00010 revisions:

D.1.4 Nitrogen Oxides (NO_X) Emission Limitations for Combustion Turbine [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD Requirements) ABB No.4 shall comply with the following, ~~excluding startup and shutdown emissions~~:

(1) Use dry low-NO_X combustors in conjunction with natural gas.

(2) During normal simple cycle operation (i.e., steady-state operating condition), the NO_X emissions from combustion turbine when burning natural gas shall be less than 9.0 ppmvd corrected to fifteen (15) percent oxygen, based on a twenty four (24) operating hour averaging period, which is equivalent to 36 pounds per hour.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual NO_X emissions from ABB No. 4 burning natural gas shall be less than ~~133.92~~ **132.06** tons per 12 consecutive month period **excluding startup and shutdown emissions**.

Comment 4:

A parallel enforceable oil operation NOx limit must be added within 12029: 500 x 180 x 133.92 / 36 / 8,768 = 38.18 tpy NOx rolled daily. Text needs to be added to 12029 stating that for every 180 pounds of oil operation NOx accumulated in an annual average, 36 pounds shall be subtracted from the 133.92 tpy gas operation annual average limit for the identical averaging period.

Response to Comment 4:

Fuel-based emission equivalents are sometimes used when compliance with annual emission limits is shown by fuel usage records. For A.B. Brown Unit 3 the emissions data from the CEMS will be used to demonstrate compliance with all of the NOx and CO emission limits, including the annual limits. Any startups and shutdowns using distillate oil will be included in the 240 hours per year allowed for startup and shutdown. The annual NOx limit in Condition D.4(c) has been revised as shown in Response to Comment 3; the tons per year limit is now derived solely from steady-state emissions when firing natural gas. The use of distillate oil will not result in any increase in allowable annual emissions. Therefore, there is no need for fuel-based equivalents in this permit.

Permit 12029 has been amended to add a reporting requirement and accompanying report form for distillate oil use to demonstrate compliance with the fuel oil limit, as shown below:

D.21 Reporting Requirements

(a) The Permittee shall submit the following information on a quarterly basis:

(5) For any quarter in which distillate oil is fired, a quarterly summary of the volume of distillate oil input to Unit 3 to document compliance with Condition D.2(c), shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported. For quarters in which no distillate oil is fired, the source does not need to submit a distillate oil usage report form; the fact that no oil was used will be reported on the semi-annual natural gas fired unit certification form.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION
100 North Senate Avenue
P.O. Box 6015
Indianapolis, Indiana 46206-6015
Phone: 317-233-5674
Fax: 317-233-5967

PART 70 SOURCE MODIFICATION

Distillate Oil Usage - Quarterly Report

Source Name: Southern Indiana Gas and Electric Company (SIGECO) - A. B. Brown Station
Source Address: W. Franklin Road and Welborn Road, West Franklin, Indiana 47620
Mailing Address: P. O. Box 3606, Evansville, Indiana, 47735-3606
Permit No.: SSM 129-12029-00010
Unit: combustion turbine ABB CT No. 3
Limit: The input of distillate oil shall not exceed 4268.57 thousand gallons (kgal) per twelve (12) consecutive month period.

Year: ____________

Month	Distillate Oil Usage (kgal/month)	Usage for previous eleven month(s) (kgal)	Usage for twelve month period (kgal)

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on: ____________________

Submitted by: ____________________
Title / Position: ____________________
Signature: ____________________
Date: ____________________
Phone: ____________________

Comment 5:

The 12674 166.98 pounds NOx / hour oil operation value must be made an enforceable short-term 24-hour average rolled hourly (counting only the hours operated) limit within 12029. All of the long-term limits should be inclusive of start-up and shut-down, and the total annual limited potential to emit ("LPTE") NOx for 12029 must be reduced from 193.68 to 164.46 tpy.

Response to Comment 5:

See Response to Comment 2 regarding short term emission rates. At this time, OAQ believes that it is preferable to have the startup/shutdown limits separate from the steady state emission limits. The emissions rates are expected to be lower during steady state operations. A single annual limit calculated including 240 hours of higher startup/shutdown emissions is less restrictive during years in which actual startups and shutdowns total less than 240 hours.

The annual emission limit condition for NOx in Permit 12029 for A.B. Brown Unit 3 has been revised in Conditions D.4(c) to be based on natural gas use and to exclude startup and shutdown emissions. The corresponding NOx annual limit in Permit 14021 Conditions D.1.4(b) has been adjusted based on 8,520 hours/yr of steady-state operation, and to clarify that startup and shutdown emissions are excluded. These revisions are included in the Response to Comment 3.

Comment 6:

Not having enforceable permit limits for both short and long term averages of emitted NOx amounts, and giving more lax limits for similar equipment in newer permits than for existing permits is an abuse of discretion.

Response to Comment 6:

The parts per million (ppm) and pounds per hour NOx emission rates during steady-state operation and the pounds of NOx per startup/shutdown cycle are enforceable short-term limits. The annual NOx emission limit is an enforceable long-term limit. As previously detailed in the Response to Comment 3, the BACT limit for NOx emissions in both of the current A.B. Brown permits and in the other PSD permits issued by Indiana in 2001 for simple-cycle combustion turbines with dry-low NOx combustion systems is the same, 9 ppm. There has been no relaxation of this limit in the newer permits.

The calculation of annual limits for a project are not based solely on the type of equipment being permitted, but is also dependent on the number of units being permitted and the hours per year that the source plans to operate those units. It is not improper for permits for similar units to have different annual limits.

Comment 7:

12029 D.5(a), 14021 D.1.5(a), and 12674 D.1.6(a)(1) each have a 25 ppmvd CO @ 15% O2 limit and corresponding verification requirements: 12029 D.14(b)(1), 14021 D.1.11(b)(1), and 12674 D.1.18(b)(1) for gas operation. The latter, in combination with the former, seem to bound the concentration, but the maximum amount seems unbounded.

12029 D.5(a)(1), 14021 D.1.5(a)(1), and 12674 D.1.5(a)(3) each have 60, 65, and 53.96 respectively pounds CO per turbine / hour "equivalents" for gas operation. It is in no way clear that 12029 D.14(b)(1), 14021 D.1.11(b)(1), or 12674 D.1.18(b)(1) impose the former as enforceable limits. People have some mental grasp of what a pound of pollutant is. They have far less of a clue as to what ppmvd CO @ 15% O2 is. Therefore, an enforceable short-term 24-hour average rolled hourly (counting only the hours operated) pounds CO / hour limit must be added to the texts of the drafts. Further, given the similarity of the equipment, the imposed 12029 and 14021 gas operation limits must not exceed the 12674 53.96 pounds CO / hour value absent substantial technical cause shown.

The short term CO oil operation “equivalent” in 12029 D.5(a)(2) is 61 pounds per hour, and, in 12674 D.1.6(a)(2), it is 42.96 pounds per hour. Given the similarity of the equipment, the required 12029 oil operation enforceable limit must not exceed the 12674 42.96 pounds CO / hour value absent substantial technical cause shown.

Response to Comment 7:

See Response to Comment 2.

The short-term CO limit, 25 parts per million (ppm), is the same for all three of the permits mentioned. The difference in the hourly CO emission rates in the Duke Knox permit, 12674, and the draft permits for the A.B. Brown turbine projects is primarily due to the different ambient temperatures selected as most representative for each project. The TSD for permit 12674 states that the hourly NOx and CO emission rates are based on the average site temperature of 53^{o}F. The emission rate in pounds per hour shown in the A.B. Brown permits is the rate at 0^{o}F. The applications for the A.B. Brown projects provided hourly NOx and CO emission rates at several ambient operating temperatures. At 60^{o}F, the 25 ppm CO limit for A.B. Brown Units 3 and 4 is equivalent to 52 pounds per hour of CO per unit when firing natural gas. This rate is comparable to the hourly emission rate in the Duke NOx permit when firing gas.

At 60^{o}F, the 25 ppm CO limit for A.B. Brown Units 3 when firing distillate oil is equivalent to 53 pounds per hour of CO. The reason for the lower hourly CO emission rate in the Duke Knox permit when firing distillate oil is unknown. This difference may be because A.B. Brown Unit 3 is a retrofit project, rather than a totally new turbine.

The 65 pounds per hour equivalent in 14021 was a typographical error, and has been corrected to 60 pounds per hour. This change is shown in the revised condition in the Response to Comment 8.

Comment 8:

An additional matter is the fact that there are to be enforceable longer-term averaging limits, and sources are expected to perform better, on average, in those longer terms. 14021 D.1.5(b) has a 224.64 tons per year (“tpy”) CO “equivalent”, but there seems no text that obligates compliance. It would lead to a calculated annual average of: 224.64 x 2,000 / 8,768 = 51.24 pounds CO / hour.

Therefore, an enforceable long-term annual average rolled daily (counting only the days operated) CO tpy limit of 224.64 tpy must be added to the text of the drafts.

Response to Comment 8:

Condition D.5(c) in 12029 and Condition D.1.5(b) in 14021 limit the total CO emissions per 12 consecutive month period for steady-state operation. These are limits, not “equivalents”. The Reporting Requirements conditions, D.21 in 12029 and D.1.13 in 14021, require a quarterly summary of the CEMS data to document compliance with Conditions D.5 and D.1.5, respectively. That reporting requirement includes the annual CO limits.

Upon further review, it has been determined that the annual CO limits for 12029 and for 14021 should be based on the hourly emissions when firing natural gas at 60^{o}F average ambient operating temperature. At 60^{o}F, the hourly emission rate for 12029 and 14021 is 52 lbs/hr of NOx when firing natural gas. A maximum of 240 hours per year are allowed for startup and shutdown. Therefore, the annual emission limits for steady state operation are derived using 8,520 hours/year. (8,760 hours/ year - 240 hours/year = 8,520 hours/year). This results in allowable emissions of 221.52 tons of CO per twelve consecutive month period for each turbine, excluding startup and shutdown.

The following conditions have been revised as shown. In Permit 12029, the lettering of the condition subparts was also corrected. In Permit 14021 Condition D.1.5, the movement of the wording “excluding startup and shutdown emissions" also clarifies that good combustion practices shall be applied at all times, including during startup and shutdown.

Permit 029-12029-00010 revisions:

D.5 PSD Carbon Monoxide (CO) - BACT Limits [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), ABB CT No. 3 shall comply with the following:

(a) Except during periods of startups and shutdowns, the CO emission rate shall not exceed a twenty-four (24) hour average concentration of 25 ppmvd corrected to 15 percent O_2.

(1) When firing natural gas, this is equivalent to 60 pounds of CO per hour at the maximum heat input condition.

(2) When firing distillate oil, this is equivalent to 61 pounds of CO per hour at the maximum fuel heat input condition.

~~(c)~~**(b)** Perform good combustion practices to minimize CO emissions.

~~(d)~~**(c)** Annual CO emissions, ~~including~~ **excluding** startup and shutdown emissions, shall not exceed ~~263.05~~ **221.52** tons per twelve (12) consecutive month period.

Permit 029-14021-00010 revisions:

D.1.5 Carbon Monoxide (CO) Emission Limitations for Combustion Turbines [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), ABB No.4 shall comply with the following, ~~excluding startup and shutdown emissions~~:

(1) During normal simple cycle operation (i.e., steady-state operating condition), the CO emissions from combustion turbine, when burning natural gas, shall be less than 25 ppmvd corrected to fifteen (15) percent oxygen, based on a twenty four (24) operating hour averaging period, which is equivalent to ~~65~~ **60** pounds per hour.

(2) Good combustion practices shall be applied to minimize CO emissions.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual CO emissions from ABB No.4 burning natural gas shall be less than ~~224.64~~ **221.52** tons per 12 consecutive month period**, excluding startup and shutdown emissions**.

Comment 9:

A parallel enforceable long term average oil operation CO limit must be added within 12029. It is reasonable that the long term rate be not more than 85% of the short-term rate. Thus: 500 x 42.96 x 0.85 / 2,000 = 9.13 tpy CO rolled daily. Text needs to be added to 12029 stating that for every 53.96 pounds of oil operation CO accumulated in an annual average, 42.96 pounds shall be subtracted from the 224.64 tpy gas operation annual average limit for the identical averaging period.

Response to Comment 9:

See Response to Comment 4. The annual CO limit in Condition D.5(c) has been revised as shown in Response to Comment 8; the tons per year limit is now derived solely from steady-state emissions when firing natural gas. The use of distillate oil will not result in any increase in allowable annual emissions. Therefore, there is no need for fuel-based equivalents.

Comment 10:

The 12674 42.96 pounds CO / hour gas operation value must be made an enforceable short-term 24-hour average rolled hourly (counting only the hours operated) limit within the drafts. All of the long term limits should be inclusive of start-up and shut-down. The total annual limited potential to emit CO for 12029 should be reduced from 263.05 to 224.64 tpy.

Response to Comment 10:

See Response to Comment 2 regarding short term emission rates. At this time, OAQ believes that it is preferable to have the startup/shutdown limits separate from the steady state emission limits. The emissions rates are expected to be lower during steady state operations. A single annual limit calculated including 240 hours of higher startup/shutdown emissions would be less restrictive during years in which actual startups and shutdowns totaled less than 240 hours.

The annual emission limit condition for CO in Permit 12029 for A.B. Brown Unit 3 has been revised in Conditions D.5(c) to be based solely on natural gas use and to exclude startup and shutdown emissions. The corresponding CO annual limit in Permit 14021 Conditions D.1.5(b) has been adjusted based on 8,520 hours/yr of steady-state operation, and to clarify that startup and shutdown emissions are excluded. These revisions are included in the Response to Comment 8.

Comment 11:

Not having enforceable permit limits for both short and long term averages of emitted CO amounts and giving more lax limits for similar equipment in newer permits than for existing permits is an abuse of discretion.

Response to Comment 11:

The parts per million (ppm) CO emission rate during steady-state operation and the pounds of CO per startup/shutdown cycle are enforceable short-term limits. The annual CO emission limit is an enforceable long-term limit. As previously detailed in the Response to Comment 7, the BACT limit for CO emissions in both of the current A.B. Brown permits and in the other PSD permits issued by Indiana in 2000 and 2001 for simple-cycle combustion turbines with dry-low NOx combustion systems is the same, 25 ppm. There has been no relaxation of this limit in the newer permits.

The calculation of annual limits for a project are not based solely on the type of equipment being permitted, but is also dependent on the number of units being permitted and the hours per year that the source plans to operate those units. Therefore, it is not improper for permits for similar units to have different annual limits.

Comment 12:

Further, recognizing that the turbines are different sizes, are not the gas combustion methods for the 12029, 14021, PSEG Dearborn County PSD issued permit package 129-12517-00033 (“12517”), and Cogentrix Lawrence County PSD issued permit package 093-12432-00021 (“12432”) CT’’s all “lean premix combustion?” The idea that CO for 12029 and 14021 is proposed for 25 ppmvd CO @ 15% O2 with a 24-hour average, not including startup and shutdown, while 12517 and 12432 are issued with 6 ppmvd CO @ 15% O2 with a 24-hour average, not including startup and shutdown, is repugnant. The absurdity of permitting a gas fired lean premix combustion “peaking” CT four times the CO pollution allowance on a fuel basis as a lean premix combustion non-peaking CT should not stand for CO Best Available Control Technology.

The CO portions of the drafts must be amended to incorporate the 6 ppmvd CO @ 15% O2 concentration limit.

As a check on DEM's work, the following computations should produce the *same* approximate result:

12029 A.2, D.5(a): 60 / 1.1109 / 25 = 2.16
14021 A.2, D.1.5(a)(1): 65 / 1.1458 / 25 = 2.27
12517 A.2(a), D.1.7(a)(1): 21.3 / 1.9064 / 6 = 1.86
12432 A.2(a), D.1.7(a)(1): 23.4 / 1.9441 / 6.0 = 2.01

Given DEM's penchant for carrying digits without significance, the 20% divergence in those results is not very comforting. What is clear is that the 12029 gas operation CO should be no more than: 1.1109 / 1.9064 x 21.3 = 12.41 pounds / hour. And the 14021 CO should be no more than: 1.1458 / 1.9064 x 21.3 = 12.80 pounds / hour.

Those CO pound / hour values and the 6 ppmvd CO @ 15% O2 concentration must be made an enforceable short-term 24-hour average rolled hourly (counting only the hours operated) limit within the drafts. Giving more lax limits for similar equipment in newer permits than for existing permits is an abuse of discretion.

Response to Comment 12:

The PSEG Lawrenceburg project and the Cogentrix Lawrence County project use the larger, next-generation GE 7FA (Model 7241) turbines equipped with GE dry low-NOx combustion systems. The 7FA's use the more sophisticated DLN 2.6 combustor and achieve a better tradeoff between NOx and CO emissions. 7FA's can attain CO emission levels below 6 ppm without CO catalyst. The DLN 2.6 combustor is not available in a smaller size suitable for the mid-size 7EA turbines chosen for the A.B. Brown turbine projects. The 7EA's use the smaller DLN 1.0 type combustor. The CO emissions levels are inherent to the size and type of turbine selected.

Permit conditions are imposed for the purpose of ensuring that each proposed project that will emit pollutants at major levels uses emission control systems that represent BACT, thereby reducing the emissions to the maximum degree possible. The permit conditions that define these systems are imposed on the project as the applicant has defined it. The conditions are not intended to redefine the project. OAQ has no authority to require the applicant to install a different size of turbine than what is being proposed. The 25 ppm CO limit is currently considered to be BACT for CO for simple cycle turbines.

As noted in the Response to Comment 7, the 65 pounds per hour CO limit in 14021 was a typographical error, and has been corrected to 60 pounds per hour.

Comment 13:

It appears that SIGECO is striving to achieve minor source status for formaldehyde ("H2CO") by accepting permit terms which limit the potential to emit to less than the 42 USC 7412(a)(1) 10 tpy major source threshold.

DEM has shown some diligence in that matter in another permit. Reference 12517 A.2(a), D.1.12, and D.1.15(b). That permit was not issued in a vacuum. It was exposed for public comment. Comment had been made to DEM in re CT H2CO prior to 12517. People elected to not comment on 12517 because of the role that it played in re permit attributes and stringency leadership in Indiana. DEM has a reasonable duty to defend the stringency of permit constraints that serve to uphold the synthetic minor source H2CO status of 12517 as it issues new permits to sources having CT's who desire H2CO synthetic minor status.

Response to Comment 13:

SIGECO did not request the formaldehyde limits shown in the draft permits 12029 and 14021. IDEM chose to add the limits to provide enforceable, legally justifiable limits. The combined formaldehyde emissions from A.B. Brown Units 3 and 4 at 8,760 hours per year are calculated to be below 10 tons. The emission factors for Hazardous air pollutants (HAPs) in the A.B. Brown turbine applications were the factors current in AP-42, the primary EPA compilation of emission factors. In emission calculations for the draft permits, IDEM used the latest HAPs emission factors issued by EPA. These factors were in an August 21, 2001, memo from Sims Roy of EPA. The Sims formaldehyde emission factor for dry low-NOx turbines, also known as lean pre-mix turbines, is 0.00022 lb/MMBtu at the upper 90th percentile emission level for high (> 80%) loads. However, the Roy emission factors do not consider the increased formaldehyde emissions expected during startup and shutdown. Also, Unit 3 is a retrofit project, not a stock turbine model, and the Roy factors may not be appropriate.

There is no justification for limiting the formaldehyde emissions to this lower level. The emission calculations and formaldehyde limit conditions in 12029 and 14021 have been revised using the 2000 AP-42 emission factors. This level has been determined to be sufficiently restrictive to limit all formaldehyde emissions from Unit 3 and Unit 4 combined to less than 10 tons per year, including startup and shutdown as shown below:

0.00071 lb/MMBtu x (1110.9 + 1145.8)MMBtu/hr x 8,760 hr/yr ÷ 2,000 lb/ton
= <u>7.018 tons per year</u> < 10 tons of Formaldehyde per year.

The formaldehyde limit in 12029 Condition D.11 and 41021 Condition D.1.7 has been revised as follows:

Permit 029-12029-00010 revisions:

<u>D.11 Formaldehyde Limit [326 IAC 2-1.1-5] [326 IAC 2-4.1-1]</u>

Pursuant to 326 IAC 2-4.1-1 (New Source Toxics Control), the formaldehyde emissions from ABB CT No. 3 shall not exceed ~~0.000996~~ **0.00071** lb/MMBtu. This will limit the combined formaldehyde emissions from ABB CT No. 3 and ABB CT No.4 to less than 10 tons per year; therefore, the requirements of 326 IAC 2-4.1 are not applicable.

Permit 029-14021-00010 revisions:

<u>D.1.7 Hazardous Air Pollutant Limitations</u>

The formaldehyde emission from the ABB No.4 combustion turbine shall not exceed ~~0.000996~~ **0.00071** lb/MMBtu. This will limit the combined formaldehyde emissions from ABB No.4 and ABB No.3 below 10 tons per year and make requirements of 326 IAC 2-4.1 not applicable. Any increase in emissions greater than the threshold specified above from this project must be approved by the Office of Air Quality (OAQ) before such change may occur.

A revised spreadsheet showing HAP emissions when firing natural gas in Units 3 and 4 is attached to this TSD Addendum as an Appendix. No change will be made to the original TSD. The OAQ prefers that the TSD reflect the permit that was on public notice. Changes to the permit or technical support material that occur after the public notice are documented in this Addendum to the Technical Support Document. This accomplishes the desired result of ensuring that these types of concerns are documented and part of the record regarding this permit decision.

Comment 14:

While some may suggest that the 12517 H2CO calculated amount: 4 x 1.9064 x 0.11 x 8,768 / 2,000 = 3.68 tpy is overprotective of the 10 tpy threshold of law, there are many facets to view. The threshold is not to be violated and the fact that it has not been violated is to be ascertainable on a more or less continuous basis. DEM typically imposes a one test every five years or fewer requirement. There is little solace in 12517 D.15(f) language. As response to comment, please list “additional” H2CO tests that DEM has required for CT’s having similar language in their permits within the last 3 years.

Response to Comment 14:

PSEG Lawrenceburg Permit condition D.15(f) states: “IDEM, OAQ retain*(s)* the authority under 326 IAC 2-1-4(f) to require the Permittee to perform additional and future compliance testing as necessary.” This is a general statement that is true for any unit permitted by OAQ. It is noted that the current rule cite is 326 IAC 2-1.1-11. OAQ has not required any formaldehyde stack testing of recently permitted combustion turbines other than the initial testing required in the pre-construction approvals. The OAQ will review the result of the initial stack tests and consider future testing as part of the Part 70 Operating Permit required for this source.

Comment 15:

The USEPA 21 August 2001 Sims Roy CT Hazardous Air Pollutant memo (“Roy”) mentions a difficulty in measuring H2CO continuously and mentions that CO may play a role as a surrogate. Roy does not suggest a surrogate ratio, does not suggest a linearity of surrogacy over an operating range, and does not deal with operation below 80%. Nonetheless, Roy’s CO surrogacy has some merit.

Response to Comment 15:

The portion of the Sims memo referenced in the comment is actually in the discussion of oxidation catalyst systems, and is not relevant to the A.B. Brown turbine permits. The relevant portion of the Sims memo discusses Lean Premix Combustion and notes “For purposes of monitoring HAP performance of lean pre-mix combustor turbines, NOx emission levels characteristic of lean premix combustor technology could be used as an indicator of proper lean premix combustor performance, which in turn would assure proper operation and low HAP emissions.” This is another area that the OAQ will consider when operational information is available during the review of the Part 70 Operating Permit applications.

Comment 16:

There are a blue million (colloquial term) CO numbers within 12517. Trying to look only at the CT CO, here are some observations:

1. If the campus is operated steady state for a year, then 12517 D.1.7(a)(1) seems to suggest a 4 x 21.3 x 8,768 / 2,000 = 373.52 tpy CO value. Is that an enforceable limit?
2. If the campus is operated start and stop, then 12517 D.1.5(d) seems to suggest that for three (3) incredible years, the campus may be operated with *no* CO bound. Is there a federally enforceable CO permit bound for those 3 years? If so, what is the annual limit and how is it enforceable as a practical manner?
3. The LPTE table on Page 1 of Appendix A to the 12517 Technical Support Document (“TSD”) has a 420.95 tpy CT CO value for normal operation and an *additional* 605.54 tpy CT CO allocation for start-up and shutdown operation.

There is obviously disparity in those numbers, but for the sake of argument, ratios of the point 3 numbers may be applied to the 12517 H2CO calculated as if CO was a linear surrogate: 4 x 1.9064 x 0.11 x 8,768 / 2,000 x (420.95 + 605.54) / 420.95 = 8.97 tpy H2CO— something that is nowhere near overprotective of the 10 tpy threshold of law.

Response to Comment 16:

The PSEG Lawrenceburg permit was issued June 7, 2001, after a thirty day public comment period. A review of conditions specific to that permit is not appropriate for this Addendum.

Comment 17:

Please explain in detail all of the measurement mechanics and calculations of a H2CO test. As I visualize it:
1. A volume of composite stack gas is analyzed for H2CO, and the answer is likely a mass per unit volume.
2. A volume per unit time measurement is made for the whole stack— with the temperature and pressure *identical* to that of the point 1 sample.
3. A gas fuel flow meter may give a number, such as thousands of standard cubic feet ("scf") per minute.
4. An analysis of the gas for its specific chemical higher heating value in BTU / scf is factored.
There are many other possibilities. For example, the first analysis might give a mass H2CO per total mass of the sample and the second factor might be a stack gas mass per unit time....

Response to Comment 17:

While there are currently no promulgated reference methods for formaldehyde testing, the U.S. EPA and the IDEM would agree to the following:

A sample of stack gas is passed (bubbled) through a set of impingers (water filled glass bottles). Since Formaldehyde is highly soluble in water it will be collected in these impingers. These impingers are recovered and the water is transferred to a common container where a sample is taken and reacted with acetyl acetone. This will produce a known color change which can be measured and quantified by spectroscopy.

This will give concentration in whatever unit is needed: parts per million (ppm), milligram per dry standard cubic meter (mg/dscm), etc.

Flowrates can then be measured in the stack using EPA reference methods 1-4. This will give the airflow which can be multiplied by the concentration to give lbs/hr.

By measuring the amount of natural gas burned (in cubic feet) and then multiplying that by the Btu value of a cubic foot of gas (1050), the total heat input to the turbine can be calculated. Then the lbs/hr of formaldehyde is divided by the heat input to get lbs/MMBtu of Formaldehyde.

Alternatively, the 'F' factor specified in Appendix A of 40 CFR 60, Method 19 can be used to calculate pounds per million Btu of formaldehyde emissions.

Comment 18:

To say that there is more than an ample possibility that the errors associated with those measurements multiplied may cumulate and cause the 10 tpy threshold to be passed is an understatement. Allowing 6, 6, 0.6, and 0.6 percent error respectively for the 4 points would lead to: 8.97 x 1.06 x 1.06 x 1.006 x 1.006 = 10.20 — a violation.

Recognizing that only a single test is specified (it should be done not less than annually), a considerable safety margin is warranted as there is considerable measurement uncertainty in steady-state conditions, expectations that equipment will degrade over time (i.e. there will be deposition of solids on various combustion pathways which will be subject to perhaps annual maintenance and there will be erosion of various components which will likely be tolerated for several years prior to restoration), etc. Absent a very exhaustive continuous test regimen on similar equipment that incorporates all ranges of operations from initial start to complete stop, the amount of H2CO, particularly the amount generated in the start, idle and stop phases is unknown. What is known is that H2CO per unit fuel ratios rise dramatically as net power levels are decreased.

For those reasons, it is appropriate to apply equally protective stringency to the drafts' H2CO as was applied in 12517. Thus, in simple form, dealing with natural gas only, if the stringency of 12517 was applied to the drafts, then the following calculation would apply: 4 x 1.9064 / (1.1109 + 1.1458) x 0.11 = 0.372 pounds of H2CO per billion HHV BTU fuel.

However, rather than imposing that limit on SIGECO within 12029 D.11 and 14021 D.1.7, DEM has only asked for 0.996 pounds H2CO per.... DEM must amend the drafts prior to issuance to incorporate the 0.372 rate test.

There are two principal caveats that are not in the simple form. T he drafts' tests incorporate a slightly stronger test than 125015 in that they test as low as 50% while 12517 only goes down to 60%. The more protective 50% test should be retained. However, 12029 permits limited oil use. In accordance with Roy, oil operation is expected to generate more H2CO than gas operation. On a possible full-load turbine hours basis for the drafts, the oil use is less than 3%. Rather than cogitate the delta favorable to SIGECO in re not factoring the oil v. the delta unfavorable to SIGECO in re the 50% v. 60% test, I propose simply amending the 0.996 rates down to 0.372 and amending 12029 D.11 and D.15(c) to indicate that it is a gas operation limit and test.

Giving more lax limits for similar equipment in newer permits than for an existing presumed viable Indiana permit is an abuse of discretion. Giving a limit that reasonably allows a source to exceed minor status is knowingly issuing a sham permit.

As an alternative to the 12517 equivalent methodology and stringency, SIGECO may freely apply for a permit amendment and incorporate continuous emissions monitoring for H2CO that will allow the calculation of an annual average rolled daily (counting only the days operated). If, for example, they installed equipment that gave recorded values that were within ± 5% of the actual H2CO amounts, then they would be entitled to permit limits for the turbines in the drafts that totaled 9.49 tpy. And, as long as they did not violate the annual rate, they could, for example, freely emit 9 tons of H2CO in 6 months.

Response to Comment 18:

As detailed in the Response to Comment 13, the revised formaldehyde emission limit for A.B. Brown Units 3 and 4 is 0.00071 lb/MMBtu. At the maximum heat input capacities of 1110.9 MMBtu/hr for Unit 3 and 1145.8 MMBtu/hr for Unit 4, this results in maximum annual formaldehyde emissions of

0.00071 lb/MMBtu x (1110.9 + 1145.8)MMBtu/hr x 8,760 hr/yr ÷ 2,000 hrs/yr = <u>7.018 tons per year</u>.

This is believed to be sufficiently conservative to account for any variation of actual emissions on a day-to-day basis and during a maximum of 240 hours per year at low loads and still prevent any exceedance of the 10 tons per year trigger level. For example, if the percent error rates presented in the comment were correct, the actual emissions would be 7.018 tons/yr x 1.06 x 1.06 x 1.006 x 1.006 = 7.980 tons per year.

As noted in the 2001 Sims Roy memo and the Response to Comment 15, the NOx emission levels are considered to be an indicator of proper lean premix combustor performance, which in turn should assure proper operation and low HAP emissions. The NOx and CO CEMS are subject to annual certification.

OAQ has the authority to request stack testing whenever it is determined to be necessary to demonstrate compliance with an applicable requirement. If the quarterly NOx and CO reports indicated that a unit is not operating properly, OAQ could request additional formaldehyde testing to confirm the compliance status of the unit.

The revised formaldehyde limit is the 2000 AP-42 emission factor for stationary natural gas-fired turbines. This value is higher than the 2000 AP-42 value for formaldehyde from distillate oil fired turbines, and higher than the formaldehyde factors in the 2001 Sims memo. Formaldehyde emissions will remain below 10 tons per year even with limited use of the backup fuel. The EPA Clean Air Markets Division does not currently recommend CEMS for formaldehyde.

Comment 19:

There are severe disparities regarding the LPTE of the existing source in the Technical Support Document tables of the drafts (11,579 v. 89,887 tpy SO2 for example). There appears to be roughly a 1,000:1 error in the flow rate in the stack summaries in the TSD's of the drafts.

Response to Comment 19:

In the source status portion of the TSDs, 12029 presented the 1998 actual emissions figures, and 14021 presented the uncontrolled potential emissions reported in the 1999 annual emission report. Neither of these approaches actually indicates the limited Potential to Emit of the source. The corrected Source Status table for the two reviews is as follows:

Source Status

Existing Source PSD Definition (emissions after controls, based upon 8760 hours of operation per year at rated capacity and/or as otherwise limited):

Pollutant	Potential To Emit (tons/year)
PM	greater than 250
PM-10	greater than 250
SO_2	greater than 250
VOC	less than 100
CO	greater than 250
NO_x	greater than 250

(a) This existing source is a major stationary source because an attainment regulated pollutant is emitted at a rate of 100 tons per year or more, and because it is one of the 28 listed source categories.

(b) These emissions are based upon the 1999 Emission Inventory Statement submitted for A. B. Brown.

Application 12029 erroneously gave the stack flow rate for Unit 3 as 1.43 kacfm. It has been determined that the value for Unit 3 should be 1,430 kacfm, or 1,430,000 acfm. The correct flow rate was used in the modeling analysis. The errant flow rate in the TSD was not used in any of the IDEM's review of this permit. The TSD Stack Summary for 12029 is corrected as shown:

Stack Summary

Stack ID	Operation	Height (feet)	Diameter (feet)	Flow Rate (acfm)	Temperature (^{0}F)
3	combustion turbine No. 3	32	18.2 x 8.6 (rectangular)	1,430**,000**	1,001

As explained in the Response to Comment 13, no change will be made to the original Technical Support Documents for 12029 and 14021.

Comment 20:

12029 D.14(b) and 14021 D.1.11(b) have "shall maintain" language following certification of continuous emissions monitors. The calibration and performance of the equipment will degrade with time. A requirement that the equipment be recertified not less frequently than annually is needed to show continuous compliance with the best available control technology limits on emissions rates and totals.

Response to Comment 20:

12029 Condition D.14(b) and 14021 Condition D.1.11(b) require the Permittee to install, calibrate, certify, operate and maintain a continuous emissions monitoring system for NO_X and CO in accordance with 326 IAC 3-5-2 and 3-5-3.

Except where 40 CFR 75 has applicable CEMs for affected facilities under the acid rain program, the quality assurance requirements of 326 IAC 3-5-5 and 40 CFR 60 Appendix F are applicable to continuous emission monitoring systems (CEMS) that monitor CO2, CO, H_2S, NOx, O_2, SO_2, total hydrocarbons, total reduced sulfur, or volatile organic compounds. There are no CEM requirements in the acid rain provisions that are applicable to combustion turbines. Therefore, 326 IAC 3-5-5 is applicable to these units. 326 IAC 3-5-5(d) does require an annual relative accuracy test (RATA) for the flow monitoring system.

To clarify that the standard operating procedures of 326 IAC 3-5-4, quality assurance requirements of 326 IAC 3-5-5, record keeping requirements of 326 IAC 3-5-6, and reporting requirements of 326 IAC 3-5-7 are all requirements for the CEMS, the rule citation has been changed in 12029 Condition D.14(b) and 14021 Condition D.1.11(b), as follows:

Permit 029-12029-00010 revision:

D.14 Continuous Emission Monitoring System (CEMS) [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5-1(d)(1), the owner or operator of this air emission source permitted under 326 IAC 2-2 and 326 IAC 2-7 shall be required to install a continuous emissions monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5.

(b) For NO_X and CO, the Permittee shall install, calibrate, certify, operate and maintain a continuous emissions monitoring system for the CT No. 3 stack in accordance with 326 IAC 3-5-2 ~~and 3-5-3~~ **through 326 IAC 3-5-7**.

Permit 029-14021-00010 revision:

D.1.11 Continuous Emission Monitoring

(a) The owner or operator of a new source with an emission limitation or permit requirement established under 326 IAC 2-5.1-3 and 326 IAC 2-2, shall be required to install a continuous emissions monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5-1(d).

(b) The Permittee shall install, calibrate, certify, operate and maintain a continuous emissions monitoring system for combustion turbine ABB No.4 stack #4 for NO_X, CO, and CO_2 or O_2 in accordance with 326 IAC 3-5-2 ~~and 3-5-3~~ **through 326 IAC 3-5-7**.

On October 26, 2001, SIGECO submitted the following comment on the proposed source modification.

Comment 21:

General Construction Condition B.3 - Permit Expiration Date

Approval to construct in accordance with PSD construction permits issued under 326 IAC 2-2 are invalid if construction is not commenced within eighteen months after receipt of approval; however 326 IAC 2-2-8(a)(1) provides that the commissioner may extend the eighteen month period upon a satisfactory showing that an extension is justified. In the proposed Modified Part 70 Permit for ABB CT Unit 3, General Construction Condition B.3 [Permit Expiration Date] currently states the following:

> Pursuant to 40 CFR 52.21(r)(2) and 326 IAC 2-2-8(a)(1)(PSD Requirements: Source Obligation), this permit to construct shall expire if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is discontinued for a continuous period of eighteen (18) months or more.

The conversion of a combustion turbine from peak load to base load is primarily an economic consideration, based in part upon trends in the natural gas market. Due to current uncertainties in the energy supply markets, SIGECO would like to ensure that it has the right currently provided under 326 IAC 2-2-8(a)(1) to request an extension of the eighteen month construction approval if necessary. With this comment, SIGECO would seek to clarify that General Construction Condition B.3 as currently proposed in the Modified Part 70 Permit for ABB CT Unit 3 does not preclude SIGECO from pursuing its right under 326 IAC 2-2-8(a)(1) to request an extension of the eighteen month construction approval period.

Response to Comment 21:

Condition B.3 has been amended to include additional wording from 326 IAC 2-2-8 and 40 CFR 52.21(r)(2), as follows:

B.3 Permit Expiration Date [326 IAC 2-2-8(a)(1)] [40 CFR 52.21(r)(2)]

Pursuant to 40 CFR 52.21(r)(2) and 326 IAC 2-2-8(a)(1) (PSD Requirements: Source Obligation), this permit to construct shall expire if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is discontinued for a continuous period of eighteen (18) months or more. **The commissioner may extend the eighteen (18) month period upon a satisfactory showing that an extension is justified.**

Upon further review, the OAQ has decided to make the following additional changes to Significant Source Modification 12029 for A.B. Brown Unit 3:

Revisions to PM_{10} Conditions:

In Permit 029-12029-00010:

The annual particulate matter limit has been revised to be based on natural gas emissions at 8,760 hours per year. The PM_{10} emission rate provided by the vendor is valid at all times, including during startup and shutdown. Therefore, there is no separate limit for periods of startup and shutdown, and the annual limit was calculated based on 8,760 hours of operation per year.

D.6 Particulate Matter (PM_{10}) - BACT Limits [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), ABB CT No. 3 shall comply with the following:

(a) Use of natural gas as primary fuel;

(b) The use of No. 2 distillate oil as a back-up fuel, limited to not more than 4268.57 thousand gallons (kgal) per twelve (12) consecutive month period;

(c) Except during periods of startups and shutdowns, the PM_{10} emission rate shall not exceed:

(1) 0.0045 lb/MMBtu when firing natural gas, which is equivalent to 5.0 pounds per hour of PM_{10}.

(2) 0.0083 lb/MMBtu when firing distillate oil, which is equivalent to 10.0 pounds per hour of PM_{10}.

(d) Perform good combustion practices to minimize PM_{10} emissions.

(e) Annual PM_{10} emissions, including startup and shutdown emissions, shall not exceed ~~23.15~~ **21.9** tons per twelve (12) consecutive month period.

(f) The total PM_{10} is the sum of filterable and condensible PM_{10}.

In Permit 029-14021-00010:

The PM_{10} emission rate provided by the vendor is valid at all times and good combustion practices are to be used at all time. Therefore, the startup/shutdown exclusion has been deleted. The identification of the indented sections has also been revised to use the standard format:

D.1.1 Particulate Matter (PM_{10}) Emission Limitations for Combustion Turbine [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements), the PM_{10} (filterable and condensible) emissions from ABB No.4 shall comply with the following~~, excluding startup/shutdown emissions~~:

~~(1)~~**(a)** Gas turbine emissions shall be less than 0.0050 pounds per MMBtu on a higher heating value basis, which is equivalent to five (5) pounds per hour.

~~(2)~~**(b)** Perform good combustion.

<u>Revision to 12029 Reporting Requirements</u>:

D.21 Reporting Requirements

(b) The Permittee shall submit the following information on a semi-annual basis:

~~(a)~~**(1)** A certification, signed by the responsible official, that certifies all of the fuels combusted during the period. The natural gas-fired facility certification does require the certification by the responsible official as defined by 326 IAC 2-7-1(34);

~~(b)~~**(2)** The natural gas ~~boiler~~ **fired facility** certification shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the six (6) month period being reported.

Appendix A: Emission Calculations
ABB CT Units No. 3 and No. 4
Natural Gas Combustion
Hazardous Air Pollutants

Company Name:	**SIGECO A.B. Brown Generatiing Station**
Address City IN Zip:	**West Franklin, IN 47620**
Pursuant to Permit # / Plt ID:	**129-12029-00010 and 129-14021-00010**
Reviewer:	Vickie Cordell and Gurinder Saini
Date:	November 14, 2001

Heat Input Capacity:	UNIT 3	1110.9	MMBtu/hr, firing natural gas
	UNIT 4	1145.8	MMBtu/hr, firing natural gas only

Hazardous Air Pollutant (HAP)	Emission Factor* (lbs/MMBtu)	Unit 3 Emissions (lbs/hr)	Unit 4 Emissions (lbs/hr)	Unit 3 Potential Emissions (tons/yr)	Unit 4 Potential Emissions (tons/yr)	Total Potential Emissions (tons/yr)
Acetaldehyde	4.000E-05	4.444E-02	4.58E-02	0.195	0.201	0.395
Acrolein	6.400E-06	7.110E-03	7.33E-03	0.031	0.032	0.063
Benzene	1.200E-05	1.333E-02	1.37E-02	0.058	0.060	0.119
1,3 Butadiene**	4.300E-07	4.777E-04	4.93E-04	0.002	0.002	0.004
Ethylbenzene	3.200E-05	3.555E-02	3.67E-02	0.156	0.161	0.316
Formaldehyde	7.100E-04	7.887E-01	8.14E-01	3.455	3.563	**7.018**
PAHs	1.800E-04	2.000E-01	2.06E-01	0.876	0.903	1.779
Propolene Oxide**	2.900E-05	3.222E-02	3.32E-02	0.141	0.146	0.287
Toluene	1.300E-04	1.444E-01	1.49E-01	0.633	0.652	1.285
Xylene	6.400E-05	7.110E-02	7.33E-02	0.311	0.321	0.633
TOTAL				5.858	6.042	**11.899**
Napthalene***	1.300E-06	1.444E-03	1.49E-03	0.006	0.007	0.013

Methodology

* Emission Factors from AP-42, Section 3.1 Table 3.1-3, as updated 4/00
** Compound was not detected. The presented emission value is based on one-half of the detection limit.
*** Speciated PAH not included in HAPs table to avoid double counting of emissions.
Potential Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760 hrs/yr x 1 ton/ 2,000 lbs

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for Part 70 Significant Source Modification

Source Background and Description

Source Name:	Southern Indiana Gas and Electric Company (SIGECO) - A. B. Brown Generating Station
Source Location:	W. Franklin Rd & Welborn Rd, West Franklin, IN 47620
Mailing Address:	P. O. Box 3606, Evansville, IN 47735-3606
County:	Posey
Sig. Source Modification No.:	129-12029-00010
SIC Code:	4911
Permit Reviewer:	Vickie Cordell

The Office of Air Quality (OAQ) has reviewed a permit application from Southern Indiana Gas and Electric Company (SIGECO) A. B. Brown Generating Station relating to the modification and operation of one (1) simple cycle, natural gas-fired combustion turbine, designated as unit ABB CT No. 3, with a maximum heat input capacity of 1110.9 MMBtu/hr (higher heating value (HHV) with natural gas fuel condition) and a maximum output of 109 MW, a nominal output of 80 MW, and utilizing No. 2 distillate oil as a back-up fuel source (maximum heat input capacity of 1195.2 MMBtu/hr at HHV condition). NOx emissions are controlled by dual fuel dry low-NOx (DLN) combustors, with steam injection for additional NOx reduction when firing distillate oil. Inlet fogging and steam augmentation may be used to enhance power production.

History

Construction permit PC (65) 1802 was issued to SIGECO for ABB CT No. 3 on November 6, 1989. Construction of a GE Frame 7EA turbine with water injection for NOx control was completed and operation commenced on June 1, 1991. PC (65) 1802 included provisions to limit the turbine emissions so that the permit did not require review pursuant to Prevention of Significant Deterioration (PSD) rules.

On March 13, 2000, SIGECO submitted an application to the OAQ requesting to remove the fuel and operation limits from the permit for ABB CT No. 3 to allow the unit to operate as a base load unit, and to add low NOx burners for NOx control, and an inlet fogging system and steam augmentation and upgraded gas path components for increased efficiency.

Air Pollution Control Justification as Integral Part of the Process

The OAQ has determined that the dry low-NOx combustor is an integral part of the combustion turbine proposed by the source. The combustion section of the unit is where fuel is introduced, ignited and burned. Without the combustor, the turbine could not operate. Based on this information, the low-NOx combustors are considered integral to the turbine. Therefore, the permitting level will be determined using the potential emissions after the low-NOx combustor. Operating conditions will be specified in the proposed permit that the dry low-NOx combustor shall operate at all times when the turbine is in operation.

Enforcement Issue

There are no enforcement actions pending for this facility.

Stack Summary

Stack ID	Operation	Height (feet)	Diameter (feet)	Flow Rate (acfm)	Temperature (^{0}F)
3	combustion turbine No. 3	32	18.2 x 8.6 (rectangular)	1,430	1,001

Recommendation

The staff recommends to the Commissioner that the Part 70 Significant Source Modification be approved. This recommendation is based on the following facts and conditions:

Information, unless otherwise stated, used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on March 13, 2000, with additional information received on April 12, 2000, and April 19, 2000.

Emission Calculations

See Appendix A of this document for detailed emissions calculations for natural gas and distillate oil usage, including hazardous air pollutant emissions (two (2) pages). Compliance shall be demonstrated by use of a continuous monitoring system for CO and NOx.

The NOx and CO emission factors in pppmvd are consistent across all ambient temperature ranges. However, the highest emissions in lbs/hr occur at lower temperatures. Therefore, the annual NOx and CO PTE in tons per year were calculated using the hourly emission values for 0EF. It is recognized that the actual average ambient temperature is closer to 60EF. The higher hourly values were used to provide a conservative estimate of the annual emissions with the use of power augmentation, which simulates lower ambient temperatures in the combustion zone. Use of the worst-case hourly emission numbers in calculating the maximum annual emissions eliminates the need for any limit or record keeping on the use of the power augmentation.

Potential To Emit of Modification

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit (PTE) is defined as “the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA.”

This table reflects the PTE for natural gas using DLN burners and the PTE for distillate oil before add-on control or fuel limit. Control equipment or a fuel limit is not considered federally enforceable until it has been required in a federally enforceable permit.

Pollutant	fuel with worst case emissions	Potential To Emit (tons/year)	PSD Threshold Level (tons/year)
PM_{10}	distillate oil	60.2	15
PM	distillate oil	22.5	25
SO_2	distillate oil	264.4	40
VOC	natural gas	10.2	40 (ozone)
CO	distillate oil	397.9	100
NO_x	distillate oil	1256.4	40

(a) This modification removes the limits that previously kept the turbine below PSD review levels. The changes to the turbine are also extensive enough for it to be reviewed as a new unit for PSD evaluation. Therefore, the full PTE was considered in all steps of the PSD review, including the BACT evaluations, rather than the increase in PTE above the baseline emissions for the unit. This is consistent with PSD requirements for review as if the unit had not been previously permitted. [40 CFR 52.21(r)(4)]

(b) Allowable emissions (as defined in the Indiana Rule) of NOx, SO_2, PM_{10}, and CO from the modification are greater than 25 tons per year. Therefore, pursuant to 326 IAC 2-1, Sections 1 and 3, a source modification is required.

HAP's	Potential To Emit, natural gas (tons/year)	Potential To Emit, distillate oil (tons/year)	PSD Threshold Level (tons/year)
Acetaldehyde	.219	.159	
Benzene	.706	.435	
Cadmium		.025	
Chromium		.057	
Formaldehyde	1.070	1.471	
Lead		.074	0.6
Manganese		4.130	
Mercury		.006	0.1
Nickel		.272	
POM	.021	.458	
TOTAL	2.016	7.087	

This table reflects the PTE before controls, and before the distillate oil fuel limit. Control equipment or a fuel limit is not considered federally enforceable until it has been required in a federally enforceable permit. The HAP emission factors used are from the August 21, 2001, combustion turbine memo from Roy Sims, EPA.

Justification for Modification

The Part 70 Operating permit is being modified through a Part 70 Significant Source Modification. This modification is being performed pursuant to 326 IAC 2-7-10.5(f) and 326 IAC 2-2.

County Attainment Status

The source is located in Posey County.

(a) Volatile organic compounds (VOC) and oxides of nitrogen (NOx) are precursors for the formation of ozone. Therefore, VOC emissions are considered when evaluating the rule applicability relating to the ozone standards. Posey County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

(b) Posey County has been classified as attainment or unclassifiable for SO_2, PM_{10} and CO. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

Source Status

Existing Source PSD Definition (emissions after controls, based upon 8760 hours of operation per year at rated capacity and/or as otherwise limited):

Pollutant	Emissions (ton/yr)
PM	901.6
PM10	306.4
SO_2	11,579.1
VOC	49.0
CO	422.7
NO_x	6,938.2

(a) This source is an existing major stationary source because at least one regulated attainment pollutant is emitted at a rate of 250 tons per year or greater. This source is also one of the 28 listed source categories. Therefore, pursuant to 326 IAC 2-2, and 40 CFR 52.21, the PSD requirements apply.

(b) These emissions are based upon the 1998 Emission Inventory Statement.

Part 70 Permit Determination

326 IAC 2-7 (Part 70 Permit Program)
This new source is subject to the Part 70 Permit requirements because the potential to emit (PTE) of:

(a) at least one of the criteria pollutant is greater than or equal to 100 tons per year,

(b) a single hazardous air pollutant (HAP) is greater than or equal to 10 tons per year, or

(c) any combination of HAPs is greater than or equal to 25 tons/year.

SIGECO A.B. Brown Station submitted an application for a Part 70 (Title V) permit application on October 8, 1996. The Part 70 permit has not been issued yet.

Potential to Emit of Modification After Issuance

The table below summarizes the potential to emit, reflecting all limits, of the significant emission units after controls and the distillate oil fuel limit. The control equipment and fuel limit are considered federally enforceable only after issuance of this Part 70 source modification.

	Potential to Emit (PTE) (tons/year)					
Process/facility	PM / PM-10	SO_2	VOC	CO	NO_X	HAPs
ABB CT No. 3	23.15	39.24	9.75	263.05	193.68	2.30

This table shows the maximum PTE, based on emissions from natural gas combustion at 8,260 hours per year, and emissions from distillate oil combustion at 500 hours per year. This gives the worst case emissions for all criteria pollutants and for the total HAPs emissions.

This modification to an existing major stationary source is major because the emissions are greater than the PSD significant levels for NO_X, CO, and PM-10. The original 1998 permit for ABB CT No. 3 included operation restrictions that limited emissions below PSD significant thresholds. This modification removes those permit restrictions in addition to permitting extensive physical changes to the unit. Therefore, pursuant to 326 IAC 2-2, and 40 CFR 52.21, the PSD requirements apply.

Federal Rule Applicability

(a) 40 CFR 52.21 (Prevention of Significant Deterioration)

Basis of BACT Determinations

(1) Due to the extensive modifications to the unit (replacement of all "hot gas pathway components") and removal of previous operational restrictions, ABB CT No. 3 has been reviewed as a new facility for purposes of Best Available Control Technology analysis.

(2) Pursuant to 326 IAC 2-2 (PSD), this modification is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of NO_X, CO, and PM_{10} because the potential to emit for these pollutants exceed the PSD major "significant" thresholds. Therefore, the PSD provisions require that this new source be reviewed to ensure compliance with the National Ambient Air Quality Standard (NAAQS), the applicable PSD air quality increments, and the requirements to apply the Best Available Control Technology (BACT) for the affected pollutants.

The attached modeling analysis (Appendix B) was conducted to show that the major new source does not violate the NAAQS and does not exceed the incremental consumption above eighty percent (80%) of the PSD increment for any affected pollutant.

BACT for the turbine included in this permit was determined on a case by case basis by reviewing similar process controls and new available technologies. In addition, economic, energy and environmental impacts are considered in IDEM's final decision. A control technology summary of the facility covered in this modification is included in Appendix C.

(3) Fuel Sulfur Content Limitations [40 CFR 52.21] [326 IAC 2-2]

The sulfur content of the natural gas fuel shall not exceed 0.0056 percent (%) by weight. The sulfur content of the distillate oil fuel shall not exceed 0.05 percent (%) by weight.

Compliance with these limitations limits the sulfur dioxide emissions from ABB CT No. 3 to less than 40 tons per year. Therefore, PSD BACT requirements do not apply to the SO_2 emissions.

(4) The maximum heat input capacity of ABB CT No. 3 at 0EF is 1110.9 MMBtu/hr (higher heating value (HHV)) when firing natural gas and 1195.2 MMBtu/hr when firing No. 2 distillate oil as a back-up fuel source (HHV).

(b) This source is subject to the requirements of 40 CFR Part 72-80 (Acid Rain Program). The requirements of this program are detailed in the Acid Rain, Phase II Permit. An Acid Rain permit for A.B. Brown Boilers 1 and 2 and CT 3, AR 129-5153-00010, was issued on December 31, 1997. (Note: ABB CT No. 3 was originally identified in the Acid Rain program as a planned Boiler No. 4. The identification correction is included in a pending revision to the A.B. Brown Acid Rain permit, AR 129-1441-00010.) AR 129-5153-00010 provides Phase II allowance allocations 640 tons per year for the period of 2000 to 2009 and 639 tons per year for the period of 2010 and beyond for ABB CT No. 3.

(c) 40 CFR Part 60, Subpart GG (Applicability - Stationary Gas Turbines)

The combustion turbine ABB CT No. 3 was previously, and continues to be, subject to 40 CFR Part 60, Subpart GG when firing natural gas because the heat input at peak load is equal to or greater than 10.7 gigajoules per hour, based on the lower heating value of the fuel fired.

Pursuant to 326 IAC 12-1 and 40 CFR 60, Subpart GG (Stationary Gas Turbines), the Permittee shall:

(1) limit nitrogen oxides emissions, as required by 40 CFR 60.332, to:

$$STD = 0.0075 \frac{(14.4)}{Y} + F ,$$

where STD = allowable NO_x emissions (percent by volume at 15 percent oxygen on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peck load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

(2) limit sulfur dioxide emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at 15 percent oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to 0.8 percent by weight.

Pursuant to 40 CFR Part 60, Subpart GG (Stationary Gas Turbines) and 326 IAC 12-1, within sixty (60) days after achieving maximum production rate, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall determine the NO_X, SO_2, and diluent emissions from the turbine ABB CT No. 3 exhaust stack, in accordance with 40 CFR 60.335 and Section C – Performance Testing, in order to document compliance with the Subpart GG NO_X and SO_2 limits.

(d) 40 CFR Part 60, Subpart A (General Provisions Relating to NSPS)

The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR Part 60, Subpart GG.

(e) 40 CFR 60.334(b)(2) (Alternative Sulfur Content Monitoring)

Pursuant to 40 CFR 60.334(b)(2) and the IDEM approval, issued on July 6, 1995, the Permittee may use the following schedule for monitoring sulfur content in lieu of the sulfur content determination requirements of 40 CFR Part 60, Subpart GG:

(1) The Permittee agrees to use sulfur analyses from the supplier certifications for the natural gas, provided the gas samples are taken once per quarter at the closest available proximity to the A.B. Brown Station.

(2) In the event of less than 30 days of turbine operation in a quarter, the quarterly sampling requirement is waived. For these purposes, one day of operation will be defined as any day that natural gas is burned for more than one hour.

(3) Quarterly sampling and analysis of the natural gas shall be performed according to the ASTM methods detailed in 60.335(d).

(f) There are no other New Source Performance Standards (326 IAC 12) and 40 CFR Part 60 applicable to this facility.

(g) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14 and 40 CFR Part 63) applicable to this proposed modification.

State Rule Applicability

326 IAC 2-1-3.4 (New Source Toxics Rule)

Pursuant to 326 IAC 2-4.1-1 (New Source Toxics Control), the formaldehyde emissions from ABB CT No. 3 shall not exceed 0.000996 lb/MMBtu. This will limit the combined formaldehyde emissions from ABB CT No. 3 and ABB CT No.4 to less than 10 tons per year; therefore, the requirements of 326 IAC 2-4.1 are not applicable.

Pursuant to 326 IAC 2-1.1-5, within one hundred and eighty (180) days after initial startup, the Permittee shall perform formaldehyde stack test on the CT No. 3 exhaust stack utilizing a method approved by the Commissioner when operating at 50%, 75%, and 100% load. These tests shall be performed in accordance with Section C – Performance Testing, in order to determine compliance with the Formaldehyde limit.

The modification of ABB CT No. 3 is extensive enough to be considered a reconstruction. The New Source Toxics Control rule requires any new or reconstructed major source of hazardous air pollutants (HAPs) for which there are no applicable NESHAP to implement maximum achievable control technology (MACT), determined on a case-by-case basis, when the potential to emit is greater than 10 tons per year of any single HAP. Information on emissions of the 187 hazardous air pollutants are listed in the OAQ Construction Permit Application, Form Y (set forth in the Clean Air Act Amendments of 1990). These pollutants are either carcinogenic or otherwise considered toxic and are commonly used by industry.

The HAP with the highest PTE for this project is formaldehyde. The combined formaldehyde emissions from the ABB CT No. 3 and ABB CT No. 4 projects are below 10 tons per year; therefore, the requirements of 326 IAC 2-4.1 are not applicable. Any increase in emissions greater than the threshold specified above from this project must be approved by the Office of Air Quality (OAQ) before such change may occur.

326 IAC 3-5 (Continuous Emission Monitoring System (CEMS))

(a) Pursuant to 326 IAC 3-5-1(d)(1), the owner or operator of this air emission source permitted under 326 IAC 2-2 and 326 IAC 2-7 shall be required to install a continuous emissions monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5.

(b) For NO_X and CO, the Permittee shall install, calibrate, certify, operate and maintain a continuous emissions monitoring system for the CT No. 3 stack in accordance with 326 IAC 3-5-2 and 3-5-3.

(1) The continuous emissions monitoring system (CEMS) shall measure NO_X and CO emissions rates in pounds per hour and parts per million (ppmvd). The use of CEMS to measure and record the NO_X and CO hourly emission rates is sufficient to demonstrate compliance with the limits established in the BACT analyses. To demonstrate compliance with the NO_X limit, the source shall take an average of the parts per million (ppm) over a twenty-four (24) operating hour period. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppm) over a twenty-four (24)-hour period. The source shall maintain records of the parts per million and the pounds per hour.

(2) The Permittee shall determine compliance with the Startup/Shutdown Limits utilizing data from the NO_X, CO, and CO_2 or O_2 CEMS, and the fuel flow meter, and Method 19 calculations.

(2) The Permittee shall submit to IDEM, OAQ, within ninety (90) days after monitor installation, a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4.

(3) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7.

(4) The source shall maintain records of the amount of natural gas combusted and the amount of distillate oil combusted in ABB CT No. 3 on a monthly basis.

(5) In instances of downtime, the source shall use the Missing Data Substitution Procedures outlined in 40 CFR Part 75, Subpart D, to demonstrate compliance with the NO_X limit established under the NO_X BACT Limits condition, and shall use the manufacturer's guaranteed emission rate to demonstrate compliance with the CO limit established under the CO BACT Limits condition.

(6) The source may submit to the OAQ alternative emission factors based on the source's CEMS data (collected over a period of twelve (12) consecutive months) and the corresponding site temperatures, to use in lieu of the manufacturer's guaranteed emission rates in instances of downtime. The alternative emissions factors must be approved by the OAQ prior to use in calculating emissions for the limitations established in this approval. The alternative emission factors shall be based upon collected monitoring and test data supplied from an approved continuous emissions monitoring system. In the event that the information submitted does not contain sufficient data to establish appropriate emission factors, the source shall continue to collect data until appropriate emission factors can be established. During this period of time, the source shall continue to use the manufacturer's guaranteed emission rate for CO compliance determination and use the NO_X Missing Data Substitution Procedures specified in 40 CFR Part 75, Subpart D for NO_X compliance determination, in periods of downtime.

(c) The Permittee shall follow parametric monitoring requirements for determining SO_2 emissions contained in the "*Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units"* in lieu of continuous emissions monitoring systems (CEMS).

(1) Pursuant to the procedures contained in 40 CFR 75.20, the Permittee shall complete all testing requirements to certify the use of the *"Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units"*.

(2) The Permittee shall apply to IDEM for initial certification to use the *"Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units"* , no later than 45 days after the compliance of all certification tests.

(3) All certification and compliance methods shall be conducted in accordance with the procedures outlined in 40 CFR Part 75, Appendix D.

326 IAC 3-5 (Testing Requirements)

Pursuant to 326 IAC 3-5, the Permittee shall conduct a performance test on the combustion turbine CT No. 3 exhaust stack not later than one-hundred and eighty (180) days after initial start-up in order to certify the continuous emissions monitoring systems for NO_X and CO. These tests shall be performed in accordance with Section C – Performance Testing.

326 IAC 5-1-2 (Opacity Limitations):

Pursuant to Construction Permit PC (65) 1802 issued November 6, 1999, and 40 CFR 52.21 and 326 IAC 2-2 (PSD Requirements) the opacity from the associated combustion turbine stack shall not exceed twenty (20) percent (6-minute average). This satisfies the opacity limitations required by 326 IAC 5-1 (Opacity Limitations).

326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating)

326 IAC 6-2 does not apply to the turbine because the combustion unit is not utilized for indirect heating. No other 326 IAC 6 rules apply.

326 IAC 7-1 (Sulfur Dioxide Emission Limitations):

Pursuant to 326 IAC 7-1.1-2, the sulfur dioxide emissions from the turbine shall be limited to 0.5 pounds per million Btu when firing distillate oil, the backup fuel. No 326 IAC 7 rules apply when combusting natural gas.

326 IAC 7-2-1 (Compliance and Reporting Requirements):

(a) Pursuant to 326 IAC 7-2-1, owners or operators of sources or facilities subject to 326 IAC 7-1.1 or 326 IAC 7-4, shall submit to the Commissioner reports of calendar month average sulfur content, heat content, fuel consumption, and sulfur dioxide emission rate in pounds per million Btus upon request. The reports shall be based on fuel sampling and analysis data in accordance with procedures specified under 326 IAC 3-3.

(b) Pursuant to 326 IAC 2-2-3, the Permittee shall demonstrate that the fuel oil sulfur content does not exceed 0.05 percent by weight by one of the following methods:

(1) Fuel sampling and analysis data shall be collected pursuant to the procedures specified in 326 IAC 3-7-4 for oil combustion. Computation of calculated sulfur dioxide emission rates from fuel sampling and analysis data shall be based on the emission factors contained in U.S. EPA publication AP-42, "Compilation of Air Pollutant Emission Factors", unless other emission factors based on site-specific sulfur dioxide measurements are approved by the commissioner and the U.S. EPA. Compliance or noncompliance shall be determined using a calendar month average sulfur dioxide emission rate in pounds per million Btus.

or

(2) Compliance or noncompliance may be determined by conducting a stack test for sulfur dioxide emissions from the combustion turbine, in accordance with the procedures in 326 IAC 3-6 utilizing procedures outlined in 40 CFR 60, Appendix A, Method 6.

(c) A determination of noncompliance pursuant to either of the methods specified in (b)(1) or (b)(2) above shall not be refuted by evidence of compliance pursuant to the other method.

(d) Upon written notification of a facility owner or operator to the department, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance.

326 IAC 8-1-6 (New facilities; general reduction requirements):

326 IAC 8-1-6 does not apply to the turbine because the potential to emit of VOC is not greater than or equal to 25 tons per year.

No other 326 IAC 8 rules apply.

326 IAC 9 (Carbon Monoxide Emission Limits):

Pursuant to 326 IAC 9 (Carbon Monoxide Emission Limits), the source is subject to this rule because it is a stationary source which emits CO emissions and commenced operation after March 21, 1972. However, there is no emission limit for the turbine under this rule, because the source is not an operation listed under 326 IAC 9-1-2.

326 IAC 10 (Nitrogen Oxides)

326 IAC 10 does not apply to the source because it is not located in one of the specified counties (Clark and Floyd) listed under 326 IAC 10-1-1.

Air Toxic Emissions

Indiana presently requests applicants to provide information on emissions of the 188 hazardous air pollutants set out in the Clean Air Act Amendments of 1990. These pollutants are either carcinogenic or otherwise considered toxic and are commonly used by industries. They are listed as air toxics on the Office of Air Quality (OAQ) Construction Permit Application Form Y.

(a) This modification will emit levels of air toxics less than those which constitute a major modification according to Section 112 of the 1990 Amendments to Clean Air Act.

(b) See attached spreadsheets for detailed air toxic calculations, updated to reflect the August 21, 2001, combustion turbine memo from Sims Roy, EPA (Appendix A pages 1 - 2).

Note: The HAP emission factors were updated after the modeling was completed. The emission factors for Benzene and POM are higher than those used for the HAPs modeling. The Benzene factor increased from 1.2E -5 to 1.45E-4 for natural gas and from 5.5E-5 to 8.3E-5 for distillate oil. The maximum Benzene emissions are now 0.02477 percent of the EPA Permissible Exposure Limit (PEL). The POM emission factor increased from 2.2E-6 to 4.32E-6 for natural gas and from 4.0E-5 to 8.74E-5 for distillate oil; there is no PEL for that HAP category.

Conclusion

The modification of this combustion turbine will be subject to the conditions of the attached proposed **Part 70 Significant Source Modification No. 129-12029-00010.**

Appendix A: Emission Calculations
Natural Gas-Fired Turbine, Dry-Low-NOx burners
ABB CT Unit No. 3

Company Name: **SIGECO A.B. Brown Generatiing Station**
Address City IN Zip: **West Franklin, IN 47620**
Pursuant to Permit # / Plt ID: **129-12029-00010**
Reviewer: Vickie Cordell
Date: September 4, 2001

Heat Input Capacity MMBtu/hr	Sulfur content of fuel (S)
1110.9	0.0056

				Criteria Pollutant			
	condensible PM	filterable PM	total PM	SO2	NOx	VOC	CO
Emission Factor, lb/MMBtu, lean pre-mix*	0.0047	0.0019	- - - -	0.94S	0.0990	0.0021	0.0150
Vendor guaranteed emissions in ppm**					9.0000		25.0000
Vendor guaranteed emissions in lb/hr **			5.0000		36.0000		60.0000
Potential Emissions, lb/hr, Lean-premix *	5.2212	2.1107		5.8478	109.9791	2.3329	16.6635
Maximum allowable emissions, lb/hr**			5.0000		36.0000		60.0000
Potential Emissions, Lean-premix, tons/yr *	22.87	9.24	- - - -	25.61	481.71	10.22	72.99
Potential Emissions, Guaranteed, tons/yr **			21.90		157.68		262.80
PTE @ 8,260 hrs/yr, Lean-premix, tons/yr **	21.56	8.72	- - - -	24.15	454.21	9.63	68.82
PTE @ 8,260 hrs, Guaranteed, tons/year **			20.65		148.68		247.80

Hazardous Air Pollutant (HAP)	Emission Factor* (lbs/MMBtu)	Emissions (lbs/hr)	Total Potential Emiss. (tons/yr)	PTE @ 8260 hrs (tons/yr)
Acetaldehyde	4.510E-05	5.01E-02	0.219	0.207
Benzene	1.450E-04	1.61E-01	0.706	0.665
Formaldehyde	2.200E-04	2.44E-01	1.070	1.009
POM	4.320E-06	4.80E-03	0.021	0.020
TOTAL			**2.02**	**1.90**

Methodology

Sulfur content is maximum allowable; actual data from gas supplier shows 0.00020 to 0.00035 percent by weight.
* From AP-42, Section 3.1 Tables 3.1-1 (uncontrolled and lean-premix values), 3.1-2a, and 3.1-3, updated 4/00; and August 21, 2001, Sims Roy memo.
** Provided in application. NOx guaranteed at 36 lbs/hr at all times, and at 9ppm or less except during start up & shut down.
Potential Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760 hrs/yr x 1 ton/ 2,000 lbs
Guaranteed max emissions in tons/yr are hourly max emissions x 8760 hrs/yr x 1 ton/2000 lbs.

PM-10 emission factor and guaranteed emissions are total of condensable and filterable emissions.
Worst case annual emissions are guaranteed hourly emissions @ 8,260 hrs/yr of natural gas operation, plus 500 hrs/yr of distillate oil operation. Exception is SO2 which is based on AP-42 emission factors.
*** Speciated PAH not included in HAPs table to avoid double counting of emissions.

Notes: Potential HAPs emissions included for information only.
The AP-42 factors for NOx (lean-premix), CO (lean-premix), VOC, and some of the HAPs have a "D" rating, which indicates that they are only expected to provide an order-of-magnitude value.

Appendix A: Emission Calculations
No. 2 Distillate Oil-Fired Turbine
ABB CT Unit No. 3

Company Name: **SIGECO A.B. Brown Generating Station**
Address City IN Zip: **West Franklin, IN 47620**
Pursuant to Permit # / Plt ID: **1293-12029-00010**
Reviewer: Vickie Cordell
Date: September 4, 2001

Heat Input Capacity
MMBtu/hr
1195.2 when using No. 2 distillate oil as fuel

Fuel Sulfur Content, S
%
0.05

				Criteria Pollutant			
	condensible PM	filterable PM	total PM	SO2	NOx	VOC	CO
Emission Factor, lb/MMBtu, uncontrolled*	7.20E-03	4.30E-03			8.80E-01	4.10E-04	3.30E-03
Emission Factor, lb/MMBtu, with steam inject.*	7.20E-03	4.30E-03		1.01S	2.40E-01		7.60E-02
Vendor guaranteed emissions in ppm **					42.0000		25.0000
Vendor guaranteed emissions in lb/hr **			10.0 lb/hr		180.0000		61.0000
Potential Emissions in lb/hr, steam injection *	8.6054	5.1394		60.3576	286.8480	0.4900	90.8352
Maximum allowable emissions in lb/hr **			10.0000		180.0000		61.0000
Potential Emissions, tons/yr, uncontrolled*							
Potential Emissions, tons/yr, steam injection*	37.69	22.51		264.37	1256.39	2.15	397.86
Potential Emissions, tons/yr, guaranteed **			43.80		788.40		267.18
PTE @ 500 hrs, steam injection, tons/year *	2.15	1.28		15.09	71.71	0.12	22.71
PTE @ 500 hrs, Guaranteed, tons/year **			2.50		45.00		15.25

Hazardous Air Pollutant (HAP)	Emission Factor * (lbs/MMBtu)	Emissions (lbs/hr)	Total Potential Emiss.* (tons/yr)	PTE @ 500 hrs* (tons/yr)
Acetaldehyde	3.03E-05	3.62E-02	0.159	0.009
Benzene	8.30E-05	9.92E-02	0.435	0.025
Cadmium	4.80E-06	5.74E-03	0.025	0.001
Chromium	1.08E-05	1.29E-02	0.057	0.003
Formaldehyde	2.81E-04	3.36E-01	1.471	0.084
Lead	1.42E-05	1.70E-02	0.074	0.004
Manganese	7.89E-04	9.43E-01	4.130	0.236
Mercury	1.20E-06	1.43E-03	0.006	0.000
Nickel	5.20E-05	6.22E-02	0.272	0.016
POM	8.74E-05	1.04E-01	0.458	0.026
TOTAL			**7.09**	**0.40**

Methodology

* From AP-42, Section 3.1 Tables 3.1-1, 3.1-2a, 3.1-3, 3.1-4, and 3.1-5, updated 4/00; and August 21, 2001, Sims Roy memo.
** Provided in application. SO2 emission factor from AP 42, Section #.1, Table 3.4-2, updated 5/98.
Emissions (tons/yr) = Heat input rate (MMBtu/hr) x Emission Factor (lb/MMBtu) * 8760 hr/yr / 2,000 lb/ton
Guaranteed max emissions in tons/yr are guaranteed hourly emissions x 8760 hrs/yr x 1 ton/2000 lbs; except SO2 from AP-42.
Limited Emissions (tons/yr) = Heat input rate (MMBtu/hr) x Emission Factor (lb/MMBtu) * 500 hr/yr / 2,000 lb/ton

Notes: Potential HAPs emissions included for information only.
The AP-42 factors for VOC and some of the HAPs have a "D" or "E" rating, which indicates that they are only expected to provide an order-of-magnitude value.

Air Quality Analysis

Introduction

Southern Indiana Gas and Electric Company (SIGECO) has applied for a Prevention of Significant Deterioration (PSD) permit to modify its existing facility (A.B. Brown Generating Station) near West Franklin in Posey County, Indiana. The site is located at Universal Transverse Mercator (UTM) coordinates 436915.0 East and 4195330.0 North. The proposed modification would consist of converting an existing General Electric Power Systems “Frame 7” combustion turbine from a simple cycle unit to a base load unit with unlimited operating hours. This will also involve upgrading the emissions control unit from a water-injection system to dry low-NOx emission controls. Posey County is designated as attainment for the National Ambient Air Quality Standards. These standards for Nitrogen Dioxide (NO_2), Sulfur Dioxide (SO_2), Carbon Monoxide (CO) and Particulate Matter less than 10 microns (PM_{10}) are set by the United States Environmental Protection Agency (U.S. EPA) to protect the public health and welfare.

McLaren-Hart, Inc prepared the PSD permit application for SIGECO. The permit application was received by the Office of Air Quality (OAQ) on March 13, 2000 with revised modeling received on March 17, 2000. This document provides OAQ:s Air Quality Modeling Section's review of the PSD permit application including an air quality analysis performed by the OAQ.

Air Quality Analysis Objectives

The OAQ review of the air quality impact analysis portion of the permit application will accomplish the following objectives:

A. Establish which pollutants require an air quality analysis based on source emissions.
B. Determine the ambient air concentrations of the source's emissions and provide analysis of actual stack height with respect to Good Engineering Practice (GEP).
C. Demonstrate that the source will not cause or contribute to a violation of the National Ambient Air Quality Standard (NAAQS) or Prevention of Significant Deterioration (PSD) increment.
D. Perform an analysis of any air toxic compound for the health risk factor on the general population.
E. Perform a brief qualitative analysis of the source's impact on general growth, soils, vegetation, endangered species and visibility in the impact area with emphasis on any Class I areas. The nearest Class I area is Kentucky's Mammoth Cave National Park which is 145 kilometers from the SIGECO site in Posey County, Indiana.

Summary

SIGECO has applied for a PSD construction permit to modify an existing facility (A.B. Brown Generating Station) near West Franklin in Posey County, Indiana. The PSD application was prepared by McLaren-Hart, Inc. of Cincinnati, Ohio. Posey County is currently designated as attainment for all criteria pollutants. Emission rates of three pollutants (Nitrogen Dioxide (NO_2), Carbon Monoxide (CO) and Particulate Matter less than 10 microns (PM_{10})) associated with the modification exceeded significant emission rates established in state and federal law, thus requiring air quality modeling. Modeling results taken from the Industrial Source Complex Short Term (ISCST3) model showed impacts for PM_{10} were predicted to be greater than the significant impact for purposes of a National Ambient Air Quality Standards analysis. Refined modeling for PM_{10} showed violations of the NAAQS. Additional modeling showed the SIGECO did not contribute significantly to any NAAQS violations. Analysis for PSD increment consumption was necessary for PM_{10}. Results from the PSD increment analysis showed increment consumption above 80% of the available PSD increment. However, SIGECO had no significant impact on any receptors with concentrations above the PSD increment. According to the New Source Review Workshop Manual, October, 1990, “The source will not be considered to cause or contribute to the violation if its own impact is not significant at any violating receptor at the time of each predicted violation." Those receptors were found 10 kilometers south and southeast of the facility. OAQ conducted Hazardous Air Pollutant (HAPs) modeling and all HAP 8-hour maximum concentrations modeled below 0.5% of each Permissible Exposure Limit (PEL). There was no impact review conducted for the nearest Class I area, which is Mammoth Cave National Park in Kentucky. No Class I analysis is required if a source is located more than 100 kilometers (61 miles) from the nearest Class I area. An additional impact analysis on the surrounding area was conducted and no significant impact on economic growth, soils, vegetation, federal and state endangered species or visibility from SIGECO was expected.

Part A - Pollutants Analyzed for Air Quality Impact

Indiana Administrative Code (326 IAC 2-2) PSD requirements apply in attainment and unclassifiable areas and require an air quality impact analysis of each regulated pollutant emitted in significant amounts by a new major stationary source or modification. Significant emission levels for each pollutant are defined in 326 IAC 2-2-1. CO, NO_x, SO_2, VOCs and PM_{10} will be emitted from SIGECO and an air quality analysis is required for CO, NO_x and PM_{10}, all of which exceeded their significant emission rates as shown in Table 1. It should be noted that all emissions are based on the Best Available Control Technology (BACT) determination and other limitations resulting from the OAQ review of the application.

TABLE 1 – SIGECO Significant Emission Rates (tons/yr)

Pollutant	Maximum Allowable Emissions	Significant Emission Rate
CO	263.1	100.0
NO_x	193.7	40.0
PM_{10}	23.2	15.0
SO_2	39.2	40.0
VOC (ozone)	9.8	40.0

Significant emission rates are established to determine whether a source is required to conduct an air quality analysis. If a source exceeds the significant emission rate for a pollutant, air dispersion modeling is required for that specific pollutant. A modeling analysis for each pollutant is conducted to determine whether the source's modeled concentrations would exceed significant impact levels. If modeled concentrations are below significant impact levels, the source is not required to conduct further air quality modeling. Modeled concentrations exceeding the significant impact level trigger the requirement to conduct more refined modeling which includes source inventories and background data. These procedures are defined in AGuidelines for Air Quality Maintenance Planning and Analysis, Volume 10, Procedures for Evaluating Air Quality Impacts of New Stationary Sources@ October 1977, U.S. EPA Office of Air Quality Planning and Standards (OAQPS).

Part B - Significant Impact Analysis

An air quality analysis, including air dispersion modeling, was performed to determine the maximum concentrations of the source emissions on receptors outside of the facility property lines. A worst-case approach for emission estimates was taken due to the nature of the operational capability of the facility.

Model Description

The Office of Air Quality review used the Industrial Source Complex Short Term (ISCST3) model, Version 3, dated April 10, 2000 to determine maximum off-property concentrations or impacts for each pollutant. All regulatory default options were utilized in the United States Environmental Protection Agency (U.S. EPA) approved model, as listed in the 40 Code of Federal Register Part 51, Appendix W AGuideline on Air Quality Models@. The Auer Land Use Classification scheme was referred to determine the land use in a 3 kilometer (1.9 miles) radius from the source. The area is considered primarily agricultural with a portion of the area industrial, therefore a rural classification was used. The model also utilized the Schulman-Scire algorithm to account for building downwash effects. The stack associated with the proposed modification is below the Good Engineering Practice (GEP) formula for stack heights. This indicates wind flow over and around surrounding buildings can influence the dispersion of concentrations coming from the stack. 326 IAC 1-7-3 requires a study to demonstrate that excessive modeled concentrations will not result from stacks with heights less than the GEP stack height formula. These aerodynamic downwash parameters were calculated using U.S. EPA=s Building Profile Input Program (BPIP).

Meteorological Data

The meteorological data used in the ISCST3 model consisted of the latest five years of available surface data from the Evansville, Indiana Airport National Weather Service station merged with the mixing heights from Peoria, Illinois Airport National Weather Service station. The 1990-1994 meteorological data was purchased through the National Oceanic and Atmospheric Administration (NOAA) and National Climatic Data Center (NCDC) and preprocessed into ISCST3-ready format with U.S. EPA=s PCRAMMET.

Receptor Grid

Ground-level points (receptors) surrounding the source are input into the model to determine the maximum modeled concentrations that would occur at each point. OAQ modeling utilized receptor grids out to 50 kilometers (12.4 miles) for all pollutants. A Polar grid was used with distances starting at 300 meters and going out to 50 kilometers. Receptors were placed at 10 degree increments for each of the 16 distances. Receptors were also placed at surrounding hilltops with the elevation differences modeled.

Modeled Emissions Data

The modeling used the emission rates listed in Table 5-1 of the application and was reviewed and revised by OAQ. Research and communication with U.S. EPA and other states during the review has led to revisions from the SIGECO submittal in the OAQ modeling review. OAQ modeling results reflect these emissions and are considered the controlling results for this air quality analysis.

Modeled Results

Maximum modeled concentrations for each pollutant over its significant emission rate are listed below in Table 3 and are compared to each pollutant=s significant impact increment for Class II areas, as specified by U.S. EPA in the Federal Register, Volume 43, No. 118, pg 26398 (Monday, June 19, 1978).

TABLE 3 - Summary of OAQ Significant Impact Analysis (ug/m3)

Pollutant	Year	Time-Averaging Period	SIGECO Maximum Modeled Impacts	Significant Impact Levels	Significant Monitoring Levels
CO	1994	1-hour	139.2	**2000.0**	[a]
CO	1994	8-hour	55.2	**500.0**	575.0
NO_2	1994	Annual – 8760 hrs/yr	0.3	**1.0**	14.0
PM_{10}	1994	24-hour	5.3	**5.0**	10.0
PM_{10}	1994	Annual - 8760 hrs/yr	0.04	**1.0**	[a]

[a] No limit exists for this time-averaged period

Background Concentrations

Modeling results indicate that of the pollutants which exceeded significant emission rates, PM_{10} impacts were above pre-construction monitoring de minimis levels specified in 326 IAC 2-2. Table 3 above shows the results of the pre-construction monitoring analysis. PM_{10} exceeded the de minimis monitoring limit. SIGECO has satisfied the pre-construction monitoring requirement, using PM_{10} monitoring data, considered conservative of the area, from the 2300 West Illinois Street monitor in Evansville, approximately 15 kilometers from the facility.

Background concentrations for use in the NAAQS analysis were required since the results of the modeling for PM_{10} concentrations exceeded their significant impact levels. The background concentrations are listed below in Table 4.

TABLE 4 - Background Concentrations (ug/m3)			
Pollutant	**Monitor Location**	**Time-Averaging Period**	**Monitored Concentrations**
PM_{10}	2300 West Illinois St.	2nd highest 24-hour	61.0
VOC (ozone)	St. Philips	1-hour	114.0 ppb

Part C - Analysis of Source Impact on NAAQS and PSD Increment

NAAQS Compliance Analysis and Results

Emission inventories of PM_{10} sources in Indiana within a 50 kilometer radius of SIGECO, taken from the OAQ emission statement database as required by 326 IAC 2-6, were supplied to the consultants. Emission inventories were required from Kentucky. EPA and OAQ have approved a screening method, using the ISCST3 model, to eliminate PM_{10} NAAQS sources and PM_{10} PSD sources from the inventory that have no significant impact in the source significant impact area for each pollutant. This method modeled all PM_{10} NAAQS and PSD sources in the 50 kilometer radius from the site. Any source that has modeled concentrations less than the significant impact level in the significant impact area of SIGECO was removed from the NAAQS and PSD inventories. Sources which did not screen out of the NAAQS and PSD inventories were included in PM_{10} refined air quality modeling. A summary of the screening results are listed in the permit application.

NAAQS modeling was conducted to compare to each pollutant=s respective NAAQS limits. OAQ modeling results are shown in Table 5. Modeling results showed pollutant impacts for PM_{10} were predicted to be greater than the significant impact for purposes of a National Ambient Air Quality Standards analysis. Refined modeling for PM_{10} showed violations of the NAAQS. The additional modeling, conducted according to the New Source Review Workshop Manual showed the SIGECO did not contribute significantly to any NAAQS violations at the receptors at the time of the predicted violation. The refined modeling results are in Appendix B.

TABLE 5 - National Ambient Air Quality Standards Analysis (ug/m3)						
Pollutant	**Year**	**Time-Averaging Period**	**Modeled Source Impacts**	**Background**	**Total**	**NAAQS Limits**
PM_{10}	1990	Highest 2^{nd} high 24-hour	107.0	61.0	168.0	150.0

Part D - Ozone Impact Analysis

Ozone formation tends to occur in hot, sunny weather when NOx and VOC emissions photochemically react to form ozone. Many factors such as light winds, hot temperatures and sunlight are necessary for higher ozone production. As per OAQ instruction, McLaren-Hart submitted its own ozone transport analysis from the SIGECO. This included a wind rose analysis and a Reactive Plume Model (RPM-IV), which McLaren-Hart has used in previous ozone analysis for other projects. The results of the wind rose analysis and the RPM-IV show that any potential plume emitted from the facility would fall out to the northeast and result in small ozone impacts.

OAQ Three-Tiered Ozone Review

OAQ incorporates a three-tiered approach in evaluating ozone impacts from a single source. The first step is to determine how NOx and VOC emissions from the new source compare to area-wide NOx and VOC emissions from Posey County as well as the surrounding counties of Vanderburgh and Gibson Counties. Results from this analysis show SIGECO=s 193.7 tons/yr of NOx would comprise 1% of the area-wide NOx emissions from point, area, onroad and nonroad mobile source and biogenic (naturally-occurring emissions from trees, grass and plants) emissions. SIGECO=s 10.5 tons/yr of VOC emissions would comprise less than 1% of the area-wide VOC emissions from the different emission sources listed above.

A second step is to review historical monitored data to determine ozone trends for an area and the applicable monitored value assigned to an area for designation determinations. This value is known as the design value for an area. The nearest ozone monitors within this region is the St. Philips monitor in Posey County which is 11 kilometers or 7 miles to the north of SIGECO and is considered upwind of the facility. The design value for the St. Philips monitor for the 1-hour ozone standard over the latest three years of monitoring data is 114 parts per billion (ppb). Wind rose analysis indicates that prevailing winds in the area occur from the southwest and west-southwest during the summer months of May through September when ozone formation is most likely to occur. Ozone impacts from the SIGECO facility would likely fall north, northeast and east northeast of SIGECO.

A third step in evaluating the ozone impacts from a single source is to estimate the source individual impact through a screening procedure. The Reactive Plume Model-IV (RPM-IV) has been used in past air quality reviews to determine 1-hour ozone impacts from single VOC/NOx source emissions. RPM-IV is listed as an alternative model in Appendix B to the 40 Code of Federal Register Part 51, Appendix W AGuideline on Air Quality Models@. The model is unable to simulate all meteorological and chemistry conditions present during an ozone episode (period of days when ozone concentrations are high). Results from RPM-IV are an estimation of potential ozone impacts. Modeling for 1 hour ozone concentrations was conducted for July 12, 1995 (a high ozone day) to compare to the ozone National Ambient Air Quality Standard (NAAQS) limit. The maximum cell concentration of ozone for each time and distance specified was used to compare to the ambient ozone. OAQ modeling results assumed the short-term emission rates of NO_2 and VOCs and are shown in Appendix A. The impact (difference between the plume-injected and ambient modes) from SIGECO was 1.0 ppb early in the plume development. All ambient plus plume-injected modes were below the NAAQS limit for ozone at every time period and every distance. No modeled 1-hour NAAQS violations of ozone occurred.

In summary, ozone formation is a regional issue and the emissions from SIGECO will represent a small fraction of NOx and VOC emissions in the area. Ozone contribution from SIGECO emissions is expected to be minimal. Ozone historical data shows that the area monitors have design values below the ozone NAAQS of 120 ppb and the SIGECO ozone impact based on the emissions and modeling will have minimal impact on ozone concentrations in the area.

Part E - Analysis and Results of Source Impact on PSD Increment

Maximum allowable increases (PSD increments) are established by 326 IAC 2-2 for NO_2, SO_2 and PM_{10}. This rule limits a source to no more than 80 percent of the available PSD increment to allow for future growth. Since the impacts for PM_{10} from SIGECO were modeled above significant impact increments, a PSD increment analysis for the existing major sources in Posey County and its surrounding counties was required. The PSD minor source baseline date in Posey County for PM_{10} was established on January 9, 1978. All PSD sources in Posey and surrounding counties from SIGECO were screened.

TABLE 6 - Prevention of Significant Deterioration Analysis (ug/m3)					
Pollutant	**Year**	**Time-Averaging Period**	**Modeled Concentrations**	**PSD Increment**	**Impact on PSD Increments**
PM_{10}	1991	Highest 2^{nd} high 24-hour	35.1	30.0	117.0%

326 IAC 2-2-6 describes the availability of PSD increment and maximum allowable increases as Aincreased emissions caused by the proposed major PSD source ... will not exceed 80% of the available maximum allowable increases over the baseline concentrations for sulfur dioxide, particulate matter and nitrogen dioxide...@. The baseline concentrations were determined from modeling the existing PSD sources that impact the SIGECO significant impact area. Table 6 shows the results of the PSD increment analysis for PM_{10}. Results from the PSD increment analysis showed increment consumption above 80% of the available PSD increment. The additional modeling, conducted according to the New Source Review Workshop Manual showed the SIGECO did not contribute significantly to any NAAQS violations at the receptors at the time of the predicted violation. Those receptors were found 10 kilometers south and southeast of the facility. The results of the refined modeling are in Appendix C.

Part E - Hazardous Air Pollutant Analysis and Results

As part of the air quality analysis, OAQ requests data concerning the emission of 188 Hazardous Air Pollutants (HAPs) listed in the 1990 Clean Air Act Amendments which are either carcinogenic or otherwise considered toxic. These substances are listed as air toxic compounds on the State of Indiana, Department of Environmental Management, Office of Air Quality construction permit application Form Y. Any HAP emitted from a source will be subject to toxic modeling analysis. The modeled emissions for each HAP are the total emissions, based on assumed operation of 8760 hours per year.

OAQ performed toxic modeling using the ISCST3 model for all HAPs. Maximum 8-hour concentrations were determined and the concentrations were recorded as a percentage of each HAP Permissible Exposure Limit (PEL). The PELs were established by the Occupational Safety and Health Administration (OSHA) and represent a worker=s exposure to a pollutant over an 8-hour workday or a 40-hour workweek. In Table 7 below, the results of the HAP analysis with the emission rates, modeled concentrations and the percentages of the PEL for each HAPs are listed. All HAP concentrations were modeled below 0.5% of their respective PEL. The 0.5% of the PEL represents a safety factor of 200 taken into account when determining the health risk of the general population.

TABLE 7 - Hazardous Air Pollutant Analysis					
Hazardous Air Pollutants	Total HAP Emissions	Limited HAP Emissions	Maximum 8-hour concentrations	PEL	Percent of PEL
	(tons/year)	(tons/year)	(ug/m3)	(ug/m3)	(%)
Acetaldehyde	0.195	0.184	0.0442	360000.0	0.00001
Acrolein	0.031	0.029	0.0071	250.0	0.00283
Benzene	0.346	0.071	0.0655	3200.0	0.00205
Formaldehyde	4.92	3.34	0.7853	930.0	0.08444
Naphthalene	0.190	0.016	0.0417	50000.0	0.00008
Toluene	0.632	0.596	0.1438	750000.0	0.00002
Xylene	0.311	0.294	0.0708	435000.0	0.00002
Metallic Hazardous Air Pollutants					
Arsenic	0.0576	0.0033	0.013	10.0	0.13092
Beryllium	0.0016	0.00009	0.00037	2.0	0.01842
Cadmium	0.0251	0.00143	0.00571	5.0	0.11429
Chromium	0.0576	0.0033	0.013	500.0	0.00262
Lead	0.0733	0.0042	0.016	50.0	0.03331
Manganese	4.136	0.2361	0.94	5000.0	0.01880
Mercury	0.0063	0.00036	0.00142	100.0	0.00142
Nickel	0.024	0.00137	0.00548	1000.0	0.00055
Polycyclic Organic Matter	0.22	0.022	0.0476	a	---
Selenium	0.131	0.00747	0.02975	200.0	0.01487

[a] No OSHA PEL for 8-hour exposure exists at this time

Part F - Additional Impact Analysis

PSD regulations require additional impact analysis be conducted to show that impacts associated with the facility would not adversely affect the surrounding area. The SIGECO PSD permit application provided an additional impact analysis performed by McLaren-Hart. This analysis included an impact on economic growth, soils, vegetation and visibility and is listed in Section 5.5 of their application.

Economic Growth and Impact of Construction Analysis

No additional construction is expected and SIGECO will employ up to 10 people selected from the local and regional area once the facility is operational. Secondary emissions are not expected to significantly impact the area as all roadways will be paved. Industrial and residential growth is predicted to have negligible impact in the area since it will be dispersed over a large area and new home construction is not expected to significantly increase. Any commercial growth, as a result of the proposed modification, will occur at a gradual rate and will be accounted for in the background concentration measurements from air quality monitors. A minimal number of support facilities will be needed. There will be no adverse impact in the area due to industrial, residential or commercial growth.

Soils Analysis

Secondary NAAQS limits were established to protect general welfare, which includes soils, vegetation, animals and crops. Soil types in Posey County are of the Allison, Huntington and Genesee Association of which is Bloomfield and Chelsea loamy fine sands (Soil Survey of Posey County, U.S. Department of Agriculture). The general landscape consists of Wabash Lowland or flat to gently rolling terrain (1816-1966 Natural Features of Indiana - Indiana Academy of Science). According to the insignificant modeled concentrations CO, NO_2 and PM_{10} and the HAPs analysis, the soils will not be adversely affected by the facility.

Vegetation Analysis

Due to the agricultural nature of the land, crops in the Posey County area consist mainly of corn, wheat and soybeans (1992 Agricultural Census for Posey County). The maximum modeled concentrations of SIGECO for $NO_{2,}$and PM_{10} are well below the threshold limits necessary to have adverse impacts on surrounding vegetation such as autumn bent, nimblewill, barnyard grass, bishopscap and horsetail milkweed (Flora of Indiana - Charles Deam). Livestock in the county consist mainly of hogs, beef and milk cows (1992 Agricultural Census for Posey County) and will not be adversely impacted from the modification. Trees in the area are mainly Beech, Maple, Oak and Hickory. These are hardy trees and due to the insignificant modeled concentrations, no significant adverse impacts are expected.

Federal and State Endangered Species Analysis

Federally endangered or threatened species as listed in the U.S. Fish and Wildlife Service , Division of Endangered Species for Indiana include 12 species of mussels, 4 species of birds, 2 species of bat and butterflies and 1 species of snake. The agricultural nature of the land overall has disturbed the habitats of the butterflies and snake and the proposed modification is not expected to impact the area further. The mussels and birds listed are commonly found along major rivers and lakes while the bats are found near caves. The fat pocketbook, pink mucket, ring pink, rough pigtoe and tubercled-blossom mussels have been identified as endangered or threatened species in Posey County. The impacts from SIGECO's proposed modification are not expected to adversely impact these species.

Federally endangered or threatened plants as listed in the U.S. Fish and Wildlife Service, Division of Endangered Species for Indiana list two threatened and one endangered species of plants. The endangered plant is found along the sand dunes in northern Indiana while the two threatened species do not thrive on cultivated or grazing land. The proposed modification is not expected to impact the area.

The state of Indiana list of endangered, special concern and extirpated nongame species, as listed in the Department of Natural Resources, Division of Fish and Wildlife, contains species of birds, amphibians, fish, mammals, mollusks and reptiles which may be found in the area of SIGECO. However, the impacts are not expected to have any additional adverse effects on the habitats of the species than what has already occurred from the agricultural activity in the area.

Additional Analysis Conclusions

The nearest Class I area to SIGECO is the Mammoth Cave National Park located approximately 145 km southeast in Kentucky. The proposed modification will not adversely affect the visibility at this Class I area. SIGECO is located well beyond 100 kilometers (61 miles) from Mammoth Cave National Park and will not have significant impact on the Class I area. The results of the additional impact analysis conclude the SIGECO's proposed modification will have no adverse impact on economic growth, soils, vegetation, endangered or threatened species or visibility on any Class I area.

APPENDIX A - RPM-IV Modeling for SIGECO				
NAAQS Analysis for Ozone (July 12, 1995)				
Time	**Distance**	**Ambient**	**Plume-Injected**	**Source Impact**
(hours)	(meters)	(ppb)	(ppb)	(ppb)
700.0	116.0	66.7	67.1	0.4
800.0	4920.0	80.0	76.6	-3.4
900.0	18100.0	93.4	92.5	-0.9
1000.0	33700.0	105.0	105.0	0.0
1100.0	45400.0	113.0	114.0	1.0
1200.0	57900.0	117.0	117.0	0.0
1300.0	73600.0	118.0	118.0	0.0
1400.0	88100.0	118.0	117.0	-1.0
1500.0	102000.0	118.0	116.0	-2.0
1600.0	116000.0	117.0	115.0	-2.0
1700.0	130000.0	117.0	115.0	-2.0
1800.0	142000.0	116.0	114.0	-2.0
1900.0	152000.0	116.0	114.0	-2.0

APPENDIX B-SIGECO's Contribution to NAAQS Exceedances

Date	UTM East	UTM North	Modeled Concentrations	Monitor Value	Total	SIGECO Contribution	SIGECO % of Total
09/18/1990	439564.2	4188732.3	107.48	61	168.48	0	0
12/28/1990	437690.9	4192655.5	102.95	61	163.95	0	0
11/07/1993	440670	4189247.8	90.74	61	151.74	0	0

APPENDIX C- SIGECO's Contribution to PSD Increments Exceedances

Date	UTM East	UTM North	Modeled Concentrations	PSD Increment	% of Increment	SIGECO Contribution	SIGECO % of Increment
09/12/1990	438906.5	4185462	40.1	30	133.67	0	0.00
12/28/1990	440670	4189247.8	32.1	30	107.00	0	0.00
11/20/1990	438906.5	4185462	31.68	30	105.60	0	0.00
12/20/1990	440590.2	4185913	30.94	30	103.13	0	0.00
07/07/1990	440590.2	4185913	30.53	30	101.77	0	0.00
11/01/1990	443597.9	4187649.5	27.74	30	92.47	0	0.00
10/06/1990	443597.9	4187649.5	25.72	30	85.73	0	0.00
03/30/1990	440590.2	4185913	25.67	30	85.57	0	0.00
08/03/1990	440590.2	4185913	25.12	30	83.73	0	0.00
11/23/1990	443597.9	4187649.5	24.64	30	82.13	0	0.00
07/08/1990	437170	4185310	24.34	30	81.13	0	0.00

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07/15/1990	436633.8	4194860	24.22	30	80.73	0	0.00
04/27/1991	440590.2	4185913	35.09	30	116.97	0	0.00
12/22/1991	442170	4186649.8	33.06	30	110.20	0	0.00
01/15/1991	440590.2	4185913	29.5	30	98.33	0	0.00
05/20/1991	440590.2	4185913	28.8	30	96.00	0	0.00
07/28/1991	440590.2	4185913	28.62	30	95.40	0	0.00
09/05/1991	440590.2	4185913	28.59	30	95.30	0	0.00
09/07/1991	440590.2	4185913	28.54	30	95.13	0	0.00
11/26/1991	442170	4186649.8	28.17	30	93.90	0	0.00
04/13/1991	440590.2	4185913	27.96	30	93.20	0	0.00
11/22/1991	440590.2	4185913	26.26	30	87.53	0	0.00
05/28/1991	440590.2	4185913	26.21	30	87.37	0	0.00
05/10/1991	437170	4185310	25.91	30	86.37	0	0.00
01/29/1991	440590.2	4185913	25.86	30	86.20	0	0.00
05/24/1991	442170	4186649.8	25.52	30	85.07	0	0.00
11/17/1991	440590.2	4185913	25.41	30	84.70	0	0.00
12/19/1991	438906.5	4185462	25.07	30	83.57	0	0.00
10/23/1991	442170	4186649.8	25	30	83.33	0	0.00
09/02/1991	438906.5	4185462	24.12	30	80.40	0	0.00
09/08/1991	442170	4186649.8	24.03	30	80.10	0	0.00
12/27/1992	440590.2	4185913	30.58	30	101.93	0	0.00
06/13/1992	440590.2	4185913	30.32	30	101.07	0	0.00
08/22/1992	438906.5	4185462	29.69	30	98.97	0	0.00
12/26/1992	440590.2	4185913	28.63	30	95.43	0.01	0.03
09/13/1993	440519.2	4185913	31.5	30	105.00	0	0.00
11/11/1993	442170	4186649.8	29.89	30	99.63	0	0.00
07/22/1993	437170	4185310	28.78	30	95.93	0	0.00
08/25/1993	438906.5	4185462	26.86	30	89.53	0	0.00
12/14/1993	440590.2	4185913	26.7	30	89.00	0	0.00
05/02/1993	440590.2	4185913	26.24	30	87.47	0	0.00
12/13/1993	440590.2	4185913	26.05	30	86.83	0	0.00
12/03/1993	440590.2	4185913	25.84	30	86.13	0	0.00
05/09/1993	438906.5	4185462	25.27	30	84.23	0	0.00
10/15/1993	440590.2	4185913	25.21	30	84.03	0	0.00
07/05/1993	442170	4186649.8	24.3	30	81.00	0	0.00
01/16/1994	440590.2	4185913	32.98	30	109.93	0	0.00
07/24/1994	436633.8	4194860	29.72	30	99.07	0	0.00
07/12/1994	440590.2	4185913	28.82	30	96.07	0	0.00
05/29/1994	438906.5	4185462	27.39	30	91.30	0	0.00
01/09/1994	440590.2	4185913	26.04	30	86.80	0	0.00

APPENDIX C

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) REVIEW

Source Name:	Southern Indiana Gas and Electric Company (SIGECO) A. B. Brown Generating Station
Source Location:	W. Franklin Road & Welborn Road, West Franklin, Indiana 47620
County:	Posey
Significant Source Mod No.:	129-12029-00010
SIC Code:	4911
Permit Reviewer:	Vickie Cordell

The Office of Air Quality (OAQ) has performed the following federal BACT review for the proposed modification and operation of one (1) simple cycle, natural gas-fired combustion turbine at the above location, designated as unit ABB CT No. 3. The unit will have a maximum heat input capacity of 1110.9 MMBtu/hr (higher heating value (HHV) with natural gas fuel condition), a maximum output of 109 MW, a nominal output of 80 MW, and will utilize No. 2 distillate oil as a back-up fuel source (maximum heat input capacity of 1195.2 MMBtu/hr at HHV condition when firing distillate oil). The modification will convert the existing General Electric Frame 7EA model combustion turbine from water injection for NO_X control to General Electric's dry low-NO_X (DLN) combustion technology system and will included upgraded gas pathway components and steam injection and inlet fogging for power augmentation.

The source is located in Posey County, which has been designated as attainment or unclassifiable for Ozone, CO, SO_2, PM_{10}, and Lead. Therefore, these pollutants were reviewed pursuant to the PSD Program (326 IAC 2-2 and 40 CFR 52.21). The NO_X, CO, and PM_{10} are subject to BACT review because the pollutant emissions are above PSD significant threshold levels stated in 326 IAC 2-2-1.

BACT is an emission limitation based on the maximum degree of reduction of each pollutant subject to the PSD requirements. In accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outline in the 1990 draft USEPA *New Source Review Workshop Manual*, this BACT analysis takes into account the energy, environment, and economic impacts on the source. These reductions may be determined through the application of available control technologies, process design, and/or operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause or contribute to air pollution thereby protecting public health and the environment.

(a) Preliminary BACT Review for NOx

Nitrogen oxide formation during combustion consists of three types, thermal NO_X, prompt NO_X, and fuel NO_X. The principal mechanism of NO_X formation during combustion is thermal NO_X. The thermal NO_X mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air. Most NO_X formed through the thermal NO_X is affected by three factors: oxygen concentration, peak temperature, and time of exposure at peak temperature. As these factors increase, NO_X emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired turbines. Emission levels vary considerably with the type and size of combustor and with operating conditions (i.e. combustion air temperature, volumetric heat release rate, load, and excess oxygen level).

The second mechanism of NO_X formation, prompt NO_X, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X reactions occur within the flame and are typically negligible when compared to the amount of NO_X formed through the thermal NO_X mechanism. The final mechanism of NO_X formation, fuel NO_X, stems from the evolution and reaction of fuel-bonded nitrogen compounds with oxygen. Characteristically natural gas contains low fuel nitrogen content, therefore, NO_X formation through the fuel NO_X mechanism is insignificant when firing natural gas.

Control Options Evaluated

The following control options were evaluated in the NO_X BACT review:

Catalytic Combustion (XONON)
Non-ammonia SCR (SCONOX)
Selective Non-catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)
Dry Low NO_X Combustors
Water/Steam Injection
Nonselective Catalytic Reduction (NSCR)

Technically Infeasible Control Options

Three of the control options are considered to be technically infeasible: XONON, SNCR, and NSCR. XONON (catalytic combustion) is a recently developed front-end technology that uses flameless combustion of fuel to reduce NO_X emissions. Catalytica, Inc. was the first to commercially develop catalytic combustion controls for smaller turbine models and markets the technology under the name of XONON. The XONON system prevents the formation of thermal NO_X during combustion of the fuel by oxidizing a fuel/air mixture across small catalyst beds to burn fuel at less that the flame temperature at which thermal NO_X formation begins. The system does use a partial flame downstream to complete the combustion process, thus, producing small amounts of NO_X emissions. XONON technology replaces the traditional diffusion or lean premix combustion cans of the combustion turbine. This technology has only been demonstrated, and being offered on small turbines (i.e. no larger than 1.5 MW). Additionally the RBLC does not list any entries for catalytic combustion as BACT for combustion turbines. Catalytic combustion technology is not yet commercially available for any of the commercial turbines in Frame 7 size. Therefore, catalytic combustion is considered to be technically infeasible for the proposed facility.

SNCR is a back-end control technology that uses ammonia injection to control NO_X. SNCR is similar to SCR, but it operates at a higher temperature range, 1,300 to 2,100 °F with an optimum temperature range from 1,600 to 1,900 °F. ABB CT No. 3 will have a maximum exhaust temperature of approximately 1,000 °F. Therefore, additional fuel combustion would be required to achieve exhaust temperatures compatible with the SNCR operation. This temperature restriction makes SNCR technically infeasible for the proposed facility.

NSCR is another back-end control technology, which is only effective in controlling certain fuel-rich reciprocating engine combustion emissions, and requires the combustion of gas to be nearly depleted of oxygen to operate. Since combustion turbines operate with high levels of excess oxygen NSCR is not technically feasible for the proposed facility.

Water and steam injection is also considered to be technically infeasible while natural gas is being combusted with DLN combustion. Water and steam injection directly into the flame area of the turbine combustor provides a heat sink that lowers the flame temperature and reduces thermal NO_X formation. The water or steam injection rate is typically described on a mass basis by a water-to-fuel ratio or a steam-to-fuel ratio. Higher water-to-fuel or steam-to-fuel ratios translate to greater NO_X reductions, but may also increase emissions of CO and other hydrocarbons, reduce turbine combustion efficiency, increase maintenance requirements and cause potential flame outs. Water or steam injection control is limited to controlling NO_X to 25 ppm @ 15% O_2. Because the proposed GE turbines will be equipped with DLN combustion that reduce NO_X to 9 ppm at 15% O_2, which is lower than that attainable with wet control, this control alternative utilizing water or steam injection will be excluded from further BACT consideration for the source when firing natural gas using the dry low NO_X combustors.

Ranking of Technically Feasible Control Options

The following technically feasible NO_X control options are ranked by control efficiency:

Rank	Control	Facility	Emission Limit (ppmvd)	Control Efficiency
1	SCONOx	Turbine	Less than 2.5	+ 90%
2	Selective Catalytic Reduction (SCR)	Turbine	2.5 – 4.5	60% - 90%
3	Dry Low NO_X Combustion	Turbine	9 – 25	N/A
4	Water/Steam Injection	Turbine	25 – 75	N/A

Discussion

Non-ammonia SCR (SCONOX)

SCONOx is an emerging technology, which offers promise of reducing combustion turbine NO_X emissions to values less than 2.5 ppm. The SCONOx system is a flue gas clean up system that uses a coated oxidation catalyst to remove both NO_X and CO, and offers promise of reducing NO_X to below 3 ppmvd. The oxidation catalyst oxidizes CO to CO_2 and NO_X to NO_2. The NO_2 is then absorbed onto a potassium carbonate coated catalyst. Because the potassium carbonate coating is consumed as part of the absorption step it must frequently by regenerated. To regenerate the potassium coating it is contacted with a reducing gas, hydrogen, in the absence of oxygen. During regeneration flue gas dampers are used to isolate a section of the coated catalyst from the flue gas path so the regeneration gases can be contacted with the catalyst. Once the catalyst has been isolated from the oxygen rich turbine exhaust, natural gas is used to generate hydrogen gas. An absence of oxygen is necessary to retain the reducing properties necessary for regeneration. Hydrogen reacts with potassium nitrites and nitrates during regeneration to form H_20 and N_2 that is emitted from the stack.

SCONOx catalyst is subject to the same fouling and masking degradation that is experienced by any catalyst operating in a turbine exhaust stream. Trace impurities either ingested from ambient air or internal sources accumulate on the surface of the catalyst, eventually masking active catalyst sites over time. Catalyst aging is also experienced with any catalyst operating within a turbine exhaust stream, however, due to the lack of experience and data with this system it is difficult to confidently predict the life and cost of the catalyst. At this time, the SCONOx system has only been applied on small industrial, cogeneration turbines. The valving system used during the regeneration step to isolate the catalyst from the exhaust gas flow requires a complete redesign before the system can be scaled up for use on units larger than that which is currently operating. There is long term maintenance and reliability concerns related to the mechanical components on the large-scale turbine projects due to the number of parts that must operate reliably within the turbine exhaust environment.

SCONOx has been demonstrated in practice on the 23 MW combined cycle Sunlaw Energy Federal facility in California with emissions demonstrated at 2-2.25 ppm range in 1997. A more recent 5 MW cogeneration combustion turbine facility has been installed at the Genetics Institute in Massachusetts. The SCONOx system at this facility operates at a narrow temperature range between 300 to 700 ^oF.

SCONOx has the potential to become a viable pollution control technology for combustion turbines once the technology can be successfully scaled up for larger turbine operations.

However, SCONOx does not represent a commercially available technology for simple cycle turbine operations such as the proposed A. B. Brown CT No. 3. Also, based on cost estimates of $6.82 million retrofit capitol cost and $2.11 million annual operating cost, SCONOx cannot be considered economically feasible for this project, with a cost per ton of NO_X of $16,491. Therefore SCONOx will not be considered further as BACT for the proposed facility. The dry low NOx combustion system is considered to be integral; therefore, these values are based on use of DLN combustion, and further removal from 9 ppmvd to 3 ppmvd for the add-on control.

Selective Catalytic Reduction

SCR is a process, which involves post-combustion removal of NO_X from the flue gas stream with a catalytic reactor. In an SCR system, ammonia is injected into the turbine exhaust gas where it reacts with nitrogen oxides and oxygen to form nitrogen and water. The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_X decomposition energy. Technical factors related to this technology include increased turbine back pressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, masking/blinding, catalyst failure, and NH_3 injection system. The catalysts are divided into two groups: base metal and zeolite.

A disadvantage common to the base metal catalyst is the inability to operate at higher temperature ranges. Due to this inability to operate at a higher temperature range, the base metal catalyst are used on the combined cycle SCR system where the exhaust gas is routed through a heat recovery steam generator. The zeolite catalyst is the only catalyst currently available that can operate at the temperature range typical of a simple cycle operation. Zeolite catalysts have a maximum temperature limit of 1,100 ^{o}F. Simple cycle operations often have short-term temperature excursion and thermal stresses associated with typical startup/shutdown applications of the simple cycle operation. According to a vendor, sustained operation at these temperatures or transient operation over these temperatures could result in permanent and premature damage to the catalyst.

There have only been three natural gas fired simple cycle facilities that have utilized a high temperature catalyst system. The City of Redding Electrical Peaking Turbines experienced catalyst masking after only 550 hours of operation. A second facility, Southern California Gas experienced a catastrophic catalyst bed failure attributed to thermal shock. All three of the facilities that are utilizing the high temperature SCR system are considerably smaller than the proposed facility. The largest facility utilizing this technology is 42 MW per turbine, which is less than half the size of the proposed facility.

A fourth installation has utilized a high-temperature zeolite-based catalyst on three (3) 83 MW simple cycle turbines firing distillate oil. This is the Puerto Rico Electric Power Authority facility located in Camblanche, Puerto Rico. These units have been operating since mid-1997 and are currently in negotiations with EPA over their ability to consistently meet the 10 ppm NO_x outlet emission rate. The problem with this operation has reportedly been the use of oil in conjunction with the SCR system and not the turbine exhaust temperature. The sulfur has been precipitating out and causing catalyst poisoning.

Based on 8,260 hours of operation per year firing natural gas and 500 hours of operation per year firing distillate oil, including 240 startup and shutdown cycles, the cost to control approximately 105 tons per year would have an overall cost effectiveness of $16,491 per ton of NO_X removed. The dry low NOx combustion system is considered to be integral; therefore, these values are based on use of DLN combustion, and further removal from 9 ppmvd to 3 ppmvd for the add-on control. This does not represent an economically feasible control option. Based on the conclusion that a high temperature SCR system is not economically feasible, and the very limited successful operating history on simple-cycle peaking applications this technology will not be considered further as BACT for NO_X at this facility.

A report issued in December 2000 by Northeast States for Coordinated Air Use Management (NESCAUM), titled "Executive Summary: Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies and Cost Effectiveness" is in agreement with this cost estimate, noting that "For installations that may be better suited for high- or low-temperature SCR variants, such as simple-cycle turbines (high-temperature SCR) or combined-cycle turbines with limited space, the cost of SCR is somewhat higher than for conventional SCR on a combined-cycle plant" and "As with conventional SCR, turbines with lower baseline NOx emissions (such as those equipped with DLN combustors) showed a higher cost per ton of NOx reduction. The estimated cost of NOx reduction for a 75 MW turbine with baseline NOx emissions of 15 ppm ranges from $5,170/ton (annual controls, high capacity factor of 85%) to as high as $20,000/ton (seasonal controls, low capacity factor of 45%)."

Water/Steam Injection and Dry Low-NOx Combustion

Water/steam injection and Dry Low NO_X combustion are common technologies viable for most turbines. The DLN technology proposed by the source, when firing natural gas, will achieve NO_X emissions levels of 9 ppmvd corrected to 15% O_2. However diesel fuel cannot be premixed with air as easily as natural gas. For this reason, the source proposed the use of water injection with a NO_X emission level of 42 ppmvd corrected to 15% O_2, in conjunction with firing diesel fuel.

<u>Existing BACT Emission Limitations</u> – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The following table represents entries in the RBLC of similar operation.

<u>TABLE 1</u>

Company	Facility	Throughput (per turbine)	Emission Rate (ppmvd at15%O2)	Control Description
Duke Knox	Turbine (8)	1158 MMBtu/hr	9 (24 operating hour average)	Dry Low NO_X (DLN) Combustion
			42 (1-hr average)	Water Injection (WI)
LSP Kendall Energy	Turbine	4 x 190 MW	25 (1-hr average)	DLN
Lyondell Harris	Turbine	1 x 160 MW	25 (1-hr average)	DLN
Tenaska	Turbine	6 x 170 MW	15 (1-hr average)	DLN
			42 (1-hr average)	WI
Dynergy Heard	Turbine	3 x 170 MW	15 (1-hr average)	DLN
Vermillon Generating Station	Turbine	8 x 80 MW	15 (1-hr average); 12 (annual average)	DLN
			42 (1-hr average)	WI
Madison Generating Station	Turbine	8 x 80 MW	15 (1-hr average); 12 (annual average)	DLN
Georgia Power	Turbine	16 x 80 MW	15 (1-hr average); 9 (base load) and 22 ("peak")	DLN
RockGen Energy	Turbine	Not specified	15 (1-hr average); 12 (24-hr average)	Good Combustion
Lee Generating Station	Turbine	8 x 80 MW	15 (1-hr average); 12 (annual average)	DLN

JEA Baldwin	Turbine	3 x 170 MW	10.5 (24-hr average)	DLN
			42 (1-hr average)	WI
Hardee Power Station	Turbine	1 x 75 MW	9 (24-hr average)	DLN
Tec Polk Power	Turbine	2 x 165 MW	10.5 (24-hr average)	DLN
			42 (1-hr average)	WI
Enron, Des Plaines	Turbine	8 x 83 MW	9 (annual average); 12 (monthly average); 15 (1-hr average)	DLN
Air Liquide	Turbine	Not specified	9 (annual average)	DLN
Wisconsin Public Service	Turbine	1 x 102 MW	9 (24-hr average); 20 ("peak power" mode limited to 100 hrs/yr)	DLN
Oleander Brevard	Turbine	3 x 170 MW	9 (24-hr average)	DLN
Vandolah Haredd	Turbine	4 x 170 MW	9 (24-hr average)	DLN
Enron, Kendall	Turbine	8 x 83 MW	9 (annual average); 12 (monthly average); 15 (1-hr average)	DLN
Wisconsin Electric	Turbine	1 x 85 MW	9 (24-hr average)	DLN
Dynergy Reidsville	Turbine	5 x 180 MW	25 (1-hr average); 15 (by retrofit)	DLN (retrofit)
LSP Nelson	Turbine	1,100 MW	15 (1-hr average)	Good Combustion
			42 (1-hr average)	WI
Wrightsville Power Facility	7EA Turbine	80 MW (simple cycle mode)	9 (24-hr average)	DLN

Based on recent EPA Region V data, there are several sources proposing NOx limits of 9 ppmvd at 15% O_2 for combustion turbines in conjunction with natural gas as fuel with a range of averaging times. The averaging periods range from annual to one (1) hour. The table above lists the NOx BACT limits for turbines in conjunction with natural gas. This table lists issued and draft permits. Even though the NSR manual states that BACT can be based on issued permits, the OAQ interprets this as a minimum requirement and the OAQ can go above and beyond the guidance of the New Source Review (NSR) Manual.

The Air Liquide, Madison and Vermillion combustion turbine projects shown in Table 1 are in operation. Madison and Vermillion have limited CEMs operational data available. Based on the Vermillion CEMs data submitted, the OAQ has determined that the source can maintain a 9 ppmvd at 15% O_2 limit during steady state operations. Air Liquide America Corporation recently received a permit from the Louisiana Department of Environmental Quality for a cogeneration project. This permit allows the turbine to emit up to 9 ppmvd of NO_x at 15 percent $O_{2,}$ over the 8,760 hours of expected annual operation in conjunction with natural gas. Additionally, compliance with this limit has been demonstrated by conducting three (3) one (1)-hour stack test runs under optimal conditions. Continuous emissions NO_x monitoring is not required on these base-load units. Therefore, due to this project being a cogeneration operation and also the fact that the permit does not require CEMS, this project is not considered comparable to the one proposed.

From EPA's *New Source Review Workshop Manual* (October 1990, page B.7), "A permit requiring the application of a certain technology or emission limit to be achieved for such technology usually is sufficient justification to assume the technical feasibility of that technology or emission limit". Since there is very limited operational continuous emissions monitoring system (CEMS) data available for turbines designed to achieve 9 ppmvd at 15% O_2, an issued permit with such emission limit is sufficient justification to require such emission limit as BACT. It is also evident that the DLN combustion technology with a guaranteed emission rate of 9 ppmvd is considered available because the source obtained such guaranteed emission rate through commercial channels. This technology is considered "applicable" because such guaranteed emission rate has been deployed (e.g. emission limit of 9 ppmvd at 15% O_2 over a 24-hour average in an issued permit) on the same or similar source. Deployment of the emission limit by such control technology on an existing source with similar gas stream characteristics, is sufficient basis for concluding technical feasibility barring a demonstration to the contrary.

Currently, there is limited operational CEMS data available for turbines guaranteed to achieve 9 ppmvd at 15% O_2. Since such data is not extensive and not based on at least four (4) months of data, the Office of Air Quality (OAQ) has determined that a NOx limit of 9 ppmvd at 15% O_2 over a 24 operating hour period is BACT. This determination is based on recent issued permits.

Even though there is an issued permit requiring a 9 ppmvd at 15% O_2 limit based over a one (1) -hour average, the OAQ believes that this averaging time is not flexible enough for this type of operation and may not be achievable based on the Vermillion Generating Stations operating data. A NOx limit of 9 ppmvd at 15% O_2 based over a 24 operating hour averaging time should allow for more operational flexibility. There could be instances when this turbine is brought on-line for only one (1) hour. Therefore, it was concluded that a 9 ppmvd at 15% O_2 limit based on a 24 operating hour averaging time under steady state conditions will limit the annual emissions and minimize the short term emissions from this unit.

The OAQ determined that the non-steady state operations, including startups and shutdowns, need a separate parts-per-million limit outside of the limits established during normal or steady state operations. This decision is based on discussions with General Electric, reviewing other issued permits for this type of operation and reviewing the Vermillion Generating Station CEMS operational data. Therefore, startup and shutdown periods (less than 50 percent load) will have a different ppm NOx limit than the normal operation limit. Most issued permits for this type of operation either allow for exceedances above the NOx emission limit through state rules, such as Florida, or allow for a startup and shutdown plan to be submitted after testing, such as Wisconsin.

<u>Conclusion</u>

Based on the information presented above, the NO_X BACT for the simple cycle combustion turbine shall be the use of natural gas as the primary fuel in conjunction with a dual-fuel Dry Low-NOx combustion system. The NO_X emissions from the turbine shall not exceed 9 ppmvd corrected to 15% O_2 averaged over a 24 operating hour period. This limit is equivalent to 36 pounds of NO_X per hour at the maximum fuel heat input condition.

The NO_X BACT for the combustion turbine when firing distillate oil shall be the use of steam injection in addition to the dual-fuel DLN combustion system as NO_X control, and an operational limitation of not more than 4268.57 thousand gallons (kgal) per twelve (12) consecutive month period, equivalent to not more than 500 hours of equivalent full load operation per year firing distillate oil. The NO_X emissions from the turbine shall not exceed 42 ppmvd corrected to 15% O_2 averaged over a twenty-four (24) hour operating period. This limit is equivalent to 180 pounds of NO_X per hour at the maximum fuel heat input condition, and 45 tons of NO_X per year while firing distillate oil.

A startup/shutdown cycle is a pair of subsequent shutdown and startup events (i.e., the shutdown following a startup represents one startup/shutdown cycle) during which the turbine operates at less than 50 percent load. Startup is defined as that period of time from initiation of combustion firing until the unit reaches steady state operation. Shutdown is defined as that period of time from the initial lowering of the turbine output, with the intent to shut down, until the time at which combustion is completely stopped. Steady state is defined as 50% load or greater. The time for each startup/shutdown cycle shall not exceed one (1) hour. Also, the source will be limited to a total of 240 startup/shutdown cycles per 12 consecutive month period, rolled on monthly basis as determined at the end of each calendar month.

During periods of startup and shutdown while firing natural gas, the NO_X emissions shall not exceed 36 pounds of NO_X per each startup/shutdown cycle. This limit is equivalent to 4.32 tons per year of NO_X during startup/shutdown if natural gas is fired.

During periods of startup/shutdown when firing distillate oil, the NO_X emission rate shall not exceed 180 pounds of NO_X per each startup/shutdown cycle. This limit is equivalent to 21.60 tons per year of NO_X during startup/shutdown if distillate oil is fired, and is included in the overall annual limit of 45 tons per year of NO_X while firing distillate oil.

The maximum potential to emit of NOx is calculated by adding the emissions for 8,260 hours per year hours per year firing natural gas at equivalent full load operation (8,760 hours/yr - 500 hours distillate oil) and the emissions for a total of 500 hours per year firing distillate oil, including the startup/shutdown emissions. The NO_X PTE for the modified turbine after controls and with the distillate oil fuel limit is 193.68 tons per year.

(b) Preliminary BACT Review for CO

Carbon monoxide emissions from combustion turbines are a result of incomplete combustion of natural gas. Improperly tuned turbines operating at off design levels decrease combustion efficiency resulting in increased CO emissions. Control measures taken to decrease the formation of NO_X during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent to newer combustion design and control systems limits the impact of fuel staging on CO emissions.

<u>Control Options Evaluated</u>

The following control options were evaluated in the CO BACT review:

High-temperature CO oxidation catalyst
Good combustion control

<u>Discussion</u>

High-temperature CO oxidation catalyst

The most stringent control for CO emissions from a combustion turbine is a CO oxidation catalyst, which can remove up to 90 percent of CO in the flue gas. Oxidation catalyst technology does not require the use of additional chemicals for the reaction to occur. The oxidation of CO to CO_2 utilizes the excess air present in the turbine exhaust and the activation energy required for the reaction to proceed in the presence of the catalyst. Technical factors relating to this technology include turbine back pressure losses, unknown catalyst life due to masking or poisoning, greater emissions and reduced market responsiveness due to startup, and potential collateral increases in the emissions of SO_3 and condensible PM_{10}. Catalytic oxidation systems operate in a relatively narrow range of temperatures. The optimum operating temperatures for these systems generally range from 700°F to 900°F. High temperature oxidation catalysts are available that can operate up to 1,200°F. Typical pressure losses across the oxidation catalyst reactor are in the range of 1.5 to 3.0 inches of water. Pressure drops at this range correspond to a 0.15 to 0.3 percent loss of power output for each 1.0 inch of water pressure loss.

Cost of an oxidation catalyst can be high with the largest cost associated with the catalyst itself. Catalyst life varies, but typically a 3 to 6 year life can be expected when used with a turbine fired solely on natural gas. However, the inability to redirect the exhaust flow when distillate oil is used as a backup fuel would result in more frequent catalyst replacement due to sulfur precipitation and catalyst poisoning. Therefore, an expected catalyst life of one year was used in calculating the cost per ton of CO removed for this facility. A high temperature CO oxidation catalyst system for A. B. Brown Unit 3 has been determined to be economically infeasible with a cost per ton of CO removed at $8,084 for this project. Total CO removed would be 210.4 tons; this is based on 80% control efficiency for 8,260 hours of operation with natural gas and 500 hours of operation with distillate oil.

Existing BACT Emission Limitations

The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the Unites States. The following table represents entries in the RBLC of similar operation:

TABLE 2

Company	Facility	Throughput (per turbine)	Emission Rate (ppmvd at 15% O2)	Control Description
Duke Knox Wheatland, IN	Turbine (SC)	8 x 80 MW	25 (hourly average)	Good Combustion
Duke Energy Madison, OH	Turbine (SC)	8 x 80 MW	25	Good Combustion
Wisconsin Public Service, WI	Turbine (SC)	1 x 102 MW	25	Good Combustion
Hardee Power Station, FL	Turbine (SC)	1 x 75 MW	20	Good Combustion
Enron, Des Plaines	Turbine (SC)	8 x 83 MW	25	Good Combustion
RockGen Energy, WI	Turbine (SC)	Not specified	12	Good Combustion
Southern Energy, WI	Turbine (SC)	4 x 170 MW	12	Good Combustion
Vermillion Generating Station, IN	Turbine (SC)	8 x 80 MW	25	Good Combustion

The cost per ton of CO removed for most of the permitted simple cycle projects, referenced in the above table, range from $1,300 - $17,000 for oxidation catalyst. Additionally, two (2) simple cycle projects located in severe ozone non-attainment areas in Illinois (Wood River (7/99) and People Gas and Light (12/98)) were permitted without an oxidation catalyst at costs of approximately $2,000 per ton of CO removed.

When reviewing the combined cycle or cogeneration projects that have been permitted to use an oxidation catalyst, most control systems were required due to LAER determinations or to avoid LAER/PSD. The cost effectiveness values for the projects not required to use an oxidation catalyst system range from $2,000 to $7,400 per ton of CO removed. These projects tend to not have limitations on the hours of operation or fuel usage, which is the same as the proposed project. The cost effectiveness value for these projects is much lower than the value determined for projects with such limitations.

The combustion turbine modification proposed for this source incorporates an efficient combustion design to minimize the CO emissions. The advanced dry low-NOx combustor system is guaranteed to maintain 25 ppmvd of CO at 15% O_2 in conjunction with natural gas, when operating under steady state conditions. Since the source is using the dry low-NOx technology to minimize NOx emissions, CO emission will be increased. The OAQ does recognize that there is a "trade-off" between NOx and CO emissions from these units. Other facilities, as listed in Table 3, have been permitted with such emission limit as BACT. Currently, the OAQ has confirmed that GE cannot guarantee an emission limit lower than 25 ppmvd for the 7EA units.

Good Combustion Control

The next type of control considered is efficient combustion control design. From Table 2, the good combustion emission control levels range from 12 ppmvd to 25 ppmvd at 15% O_2 which is based on the use of the GE 7FA DLN technology. Note that there is a range of permitted CO emission limits because different states have required different values. However, General Electric does guarantee a CO emission limit of 25 ppmvd at 15% O_2 for 7FA turbines. General Electric has confirmed that CO emissions from the 7FA model are lower than the 7EA model due to differences in design. The main difference in design between the two models is the post flame temperature. The post flame temperature in the transition piece leading up to the first stage turbine nozzle is hotter in the 7FA than the 7EA. This hotter temperature results in burning out more CO emissions. Therefore, CO emissions from the 7FA turbines are not comparable and this emission limit is excluded from further BACT consideration for this unit.

Based on the table above, the next combustion control emissions level is 20 ppmvd at 15% O_2 based on the use of the GE 7EA DLN technology. This emission limitation has only been permitted in Florida for the Hardee Power Station, TECO Power Services. This emission limitation was below the vendor guarantee of 25 ppmvd at 15% O_2. The first year of operation the source will be permitted for 25 ppmvd at 15% O_2 and thereafter have to comply with a CO limit of 20 ppmvd at 15% O_2. Compliance with this limit will be determined by stack testing. The source will not be required to install a continuous CO emission monitoring system, unlike the project proposed.

After discussing this project with the Florida Department of Environmental Protection (FDEP), the OAQ was informed that this emission limit was based on emission data from the Kern River project. The OAQ then reviewed the emission data and project briefing supplied by the FDEP. The Kern River project consists of eight (8) combustion turbines and eight (8) heat recovery steam generators. The combustion turbines are older GE 7EA turbines with water injection to control NOx emissions to 42 ppmvd at 15% O_2. To comply with the Clean Air Act of 1990, the source converted their NO_X controls from water injection at 42 ppmvd to DLN combustion at 16.4 ppmvd. This is comparable to the modification proposed for ABB CT No. 3. However, the OAQ believes that these CO emissions are not a good basis of comparison for the A. B. Brown project because retrofitting is very facility-specific. In addition, the Kern River project is a combined cycle project whose CO emissions were determined by stack tests and not CEMS data. The OAQ determined, such as the case for NOx emission data, that the CO emissions data should be based on the emissions guaranteed by GE for this specific unit. Therefore this emission limit is excluded from BACT consideration.

The combustion turbine modification proposed for this source incorporates an efficient combustor design to minimize the CO emissions. The advanced DLN system is guaranteed to maintain 25 ppmvd of CO at 15% O_2 in conjunction with natural gas, when operating at loads above 60 percent. Since the source is using the dry low-NOx technology to minimize NO_X emissions, CO emission will be increased. The OAQ does recognize that there is a "trade-off" between NOx and CO emissions from these units. Other facilities, as listed in Table 2, have been permitted with such emission limit as BACT. Currently, the OAQ has confirmed that GE cannot guarantee an emission limit lower than 25 ppmvd for the 7EA units.

Conclusion

Based on the information presented above, the CO BACT for the ABB CT No. 3 shall be the use of natural gas as the primary fuel and good combustion control. The CO emissions from ABB CT No. shall not exceed 25 ppmvd on a twenty-four (24) hour average while firing natural gas. This is equivalent to 60 pounds of CO per hour at the maximum heat input condition.

The CO BACT for the combustion turbine when firing distillate oil shall be good combustion control and an operational limitation of not more than 4268.57 thousand gallons (kgal) of distillate oil per twelve (12) consecutive month period, equivalent to not more than 500 hours of equivalent full load operation per year firing distillate oil. The CO emissions from the turbine shall not exceed 25 ppmvd on a twenty-four (24) hour average. This limit is equivalent to 61 pounds of CO per hour at the maximum fuel heat input condition, and 15.25 tons of CO per year while firing distillate oil.

A startup/shutdown cycle is a pair of subsequent shutdown and startup events (i.e., the shutdown following a startup represents one startup/shutdown cycle) during which the turbine operates at less than 50 percent load. The time for each startup/shutdown cycle shall not exceed one (1) hour. Also, the source will be limited to a total of 240 startup/shutdowns per year with natural gas or distillate oil.

During periods of startups and shutdowns while firing natural gas, the CO emission rate shall not exceed 60 pounds per hour. This limit is equivalent to 7.2 tons per year of NO_X during startup/shutdown if natural gas is fired.

During periods of startup/shutdown when firing distillate oil, the CO emission rate shall not exceed 61 pounds of CO per hour. This limit is equivalent to 7.32 tons per year of CO during startup/shutdown if distillate oil is fired, and is included in the overall annual limit of 15.25 tons per year of CO while firing distillate oil.

The maximum potential to emit of CO is calculated by adding the emissions for 8,260 hours per year firing natural gas at equivalent full load operation and the emissions for 500 hours per year firing distillate oil, including startup/shutdown emissions. The CO PTE for the modified turbine with the distillate oil fuel limit is 263.05 tons per year.

(c) Preliminary BACT Review for PM_{10}

Particulate matter emissions from natural gas combustion sources consist of inert contaminants in natural gas, sulfates from fuel sulfur or mercaptans used as odorants, dust drawn in from the ambient air, particulate if carbon and hydrocarbons resulting from incomplete combustion, and condensibles. Units firing fuel with low ash content and high combustion efficiency exhibit corresponding low particulate matter emissions.

The three potential sources of filterable particulate emissions that can result from combustion sources are mineral matter found in the fuel, solids or dust in the ambient air used for combustion, and unburned carbon or soot formed by incomplete combustion of the fuel. There is no source of mineral matter found in the fuel for natural gas-fired sources. In addition, as a precautionary measure to protect the high speed rotating equipment within a combustion turbine, the inlet combustion air is filtered prior to introduction in the combustion turbine. Finally, the potential for soot formation in a natural gas-fired combustion turbine is very low because the fuel is burned in excess air combustion conditions. Distillate oil contains only trace amounts of ash.

There are two sources of condensible particulate emissions from combustion processes: condensible organic materials that are the result of incomplete combustion, and sulfuric acid mist, which is found as sulfuric acid dihydrate. For natural gas-fired processes there should be no condensible organic material originating from the process because the main components of natural gas (i.e. methane and ethane) are not condensible at the temperature found in the Method 202 ice bath. As such, any condensible organics are from the ambient air. The most likely condensible particulate matter from natural gas-fired sources is the sulfuric acid dihydrate, which results when sulfur in the fuel and the ambient air is combusted and then cools.

Control Options Evaluated

The following control options were evaluated in the BACT review:

Baghouse (Fabric Filter)
Electrostatic Precipitator (ESP)
Good Combustion

Technically Infeasible Control Options

Traditional add on particulate control, such as listed above, have not been applied to natural gas and low sulfur diesel fuel fired combustion turbines. High temperature regimes, fine particulate and low particulate rates along with significant airflow rates make add on particulate control equipment technically infeasible.

Discussion

In order to reduce particulate emissions from a turbine assembly, combustion of clean burning fuels like natural gas and low sulfur diesel fuel is environmentally beneficial. Based on the RBLC database, good combustion practice and combustion control have been listed as the means for reducing particulate matter emissions from all sizes of turbines. The implications of this control alternative are that the proposed project operators will maintain the turbine in good working order per manufacturer’s guidance and implement good combustion.

As stated above, the combustion of natural gas and low sulfur distillate oil generates negligible amounts of particulate matter. There is a degree of variability inherent to the test method (Method 202) used to determine compliance with the proposed particulate limits. The variability from this test result is due to several factors. First, there is such a large volume of exhaust gas stream compared to small amount of particulate. For example, the concentration of particulate matter could be the same for two gas steams, however, if one of the gas streams is at a lower flow rate the pound per hour emission rate would be less than a gas stream that is at a higher flow rate. Second, as with any test there is a possibility of human error, which have the potential to bias the test higher or lower than what is actually being emitted. In addition, the inlet air filters are not a hundred percent efficient, so any particulate that passes through the filters will also leave the exhaust stack. The higher the background concentration of particulate matter in the ambient air the more will pass through the combustion turbine stack. Ambient air particulate concentration can vary depending on location, activity in the area, and weather conditions.

Conclusion

Based on the information presented above, the PM_{10} BACT shall be the use of natural gas as the primary fuel, low sulfur distillate oil as a backup fuel, and good combustion practices. The PM_{10} emission limit for combined condensible and filterable PM_{10} from the turbine when firing natural gas shall not exceed 0.0045 lb/MMBtu, which is equivalent to 5.0 pounds per hour of PM_{10}. When firing distillate oil, the combined condensible and filterable PM_{10} emissions shall not exceed 0.0083, which is equivalent to 10.0 pounds per hour when firing distillate oil.

Operation of the turbine will be limited to not more than 4268.57 thousand gallons (kgal) of distillate oil per twelve (12) consecutive month period, equivalent to 500 hours per year firing distillate oil.

The maximum potential to emit of PM_{10} is calculated by adding the emissions for 8,260 hours per year firing natural gas and the emissions for 500 hours per year firing distillate oil. The PM_{10} PTE for the modified turbine with the fuel sulfur limits and distillate oil usage limit is 23.15 tons per year.

PRELIMINARY BACT TURBINE SUMMARY:

Pollutant	BACT for natural gas firing
NOx	Use of natural gas as the primary fuel and dual-fuel dry low-NOx burners with vendor specified maximum emissions of 9 ppmvd @ 15% O_2 averaged over a 24 operating hour period; equivalent to not more than 36 pounds per hour. Emissions during each startup/shutdown cycle shall not exceed 36 pounds.
CO	Use of natural gas as the primary fuel and good combustion control. Emissions shall not exceed 25 ppmvd corrected to 15% O_2 on a 24-hour average; equivalent to 60 pounds per hour. Emissions during each startup/shutdown cycle shall not exceed 60 pounds.
PM_{10}	Use of natural gas as primary fuel and good combustion practices. Emissions shall not exceed 0.0045 lb/MMBtu; equivalent to 5 pounds per hour.

Pollutant	BACT for distillate oil firing
NOx	Use of dual-fuel dry low-NOx burners and steam injection when firing distillate oil, and not more than 4268.57 thousand gallons (kgal) of distillate oil per twelve (12) consecutive month period. Vendor specified maximum emissions of 42 ppmvd @ 15% O_2 averaged over a 24 operating hour period; equivalent to not more than 180 pounds per hour. Emissions during each startup/shutdown cycle shall not exceed 180 pounds.
CO	Good combustion control, and not more than 4268.57 thousand gallons (kgal) of distillate oil per twelve (12) consecutive month period. Vendor specified maximum emissions of 25 ppmvd @ 15% O_2 on a twenty-four (24) hour average; equivalent to not more than 61 pounds per hour. Emissions during each startup/shutdown cycle shall not exceed 61 pounds per hour.
PM_{10}	Good combustion practices and not more than 4268.57 thousand gallons (kgal) of distillate oil per twelve (12) consecutive month period. Emissions shall not exceed 0.0083; equivalent to 10 pounds per hour.

The opacity from the associated combustion turbine stack shall not exceed twenty (20) percent for any six (6)-minute averaging period.

The time for each startup/shutdown cycle shall not exceed one (1) hour. Startup/shutdown cycles shall be limited to not more than a total of 240 startup/shutdowns per 12 consecutive month period, rolled on monthly basis as determined at the end of each calendar month.